Appendix W. Report–Dynamic Simulations Deepwater Horizon Incident BP (from ae add energy)

Report

Dynamic Simulations

Deepwater Horizon Incident

BP

29 AUGUST, 2010

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Dynamic Simulations
Deepwater Horizon Incident

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ABSTRACT:

This report summarizes the modeling and dynamic simulations performed in response to the blowout occurring at the Macondo well, MC252 #1 on the 20th of April 2010. The work was done for BP's internal Investigation Team.

Simulations were performed using OLGA-WELL-KILL[1], a software developed for well control applications. Fluid characterization and properties are generated by using PVTsim[2], a software developed by Calsep.

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KEY WORDS:

Dynamic Simulations, Well Control

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[1] Powered by OLGA from SPT-Group

[2] From Calsep

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Summary

This report summarizes the dynamic simulations and evaluations performed in response to the Deepwater Horizon blowout that occurred on the 20th of April 2010. The incident occurred following a negative test performed to check the integrity of the well barriers (cement, float, casing and seal assembly). The rig personnel concluded the test was successful and the incident happened as they displaced the riser to seawater.

The analysis presented in this report was performed to gain a better understanding of the following questions:

- What was the likely flow path of the hydrocarbons to surface?
- What caused the drill pipe pressure transients during the last 30 minutes of the recorded data?
- When was the BOP operated and how did it perform?
- What was the volume of the hydrocarbons released to surface prior to the explosion?

The evaluations and findings made during this work (to the date of this report) are based on witness accounts, mud-logging data, cement-unit data, well design, reservoir properties and reservoir fluid composition.

A detailed dynamic OLGA-WELL-KILL network model was built, used and found to be a valuable tool for analyzing and understanding the transients occurring in the wellbore right before the explosion. The model includes the casing, the drill pipe, the boost line, the outer annulus, the riser, the surface piping, the mud-gas separator, pumps, valves and control systems. The fluids include seawater, 16 ppg high viscosity spacer (a combination of Form-A-Set and Form-A-Squeeze), 14 ppg mud and hydrocarbons. The start time of the simulation model is 15:00 hrs when the entire wellbore was filled with 14 ppg mud. The simulations were performed following the operations for the entire period between 15:00 hrs and 21:49 hrs.

As more information became available to the Investigation Team, the model had to be updated leading to a series of simulations. Some of these initial simulations are discussed in the report to provide the reader additional context on the scenarios considered.

The main reservoir in the MC252 Macondo prospect well consists of two oil bearing sands, the Upper and the Lower M56. Both sands have a pore pressure of 12.6 ppg. The top of the Upper M56 is at 18,086 ft TVD RKB and only a few feet separates the upper and the lower sands. The reservoir sands are very prolific. Based on 300 mD and 86 ft net pay, the inflow performance curve indicates a productivity index of 49 stb/d/psi for pressures above the bubble point pressure. This contributes to a fast unloading of the well if it is left open to flow in an underbalanced condition. For example a drawdown of only 1,000 psi results in an influx of 73 bpm of oil from the reservoir into the wellbore. This is equivalent to a rate of 34 stb/m at surface conditions, the oil formation volume factor is 2.14 bbl/stb.

It is probable that the sands were restricted to some degree by the cement and downhole equipment and that the resulting reservoir exposure is less than the total reservoir thickness.

As insights were gained from the initial simulations that were completed and more information became available from the investigation team, it was possible to converge on the inputs for further simulations to be completed. The main simulation runs that were completed are described in Section 3.6 (Early Simulations) and Section 3.7 (Final Simulations). In Section 3.6, the early simulations, a large net pay assumption of 86 ft was used and cases for flow through the production casing and through the production casing outer annulus were evaluated. In Section 3.7, the final simulations, net pay assumptions between 13 ft and 16.5 ft were used and most of the cases run were based on flow through the production casing via the casing shoe. In the simulations described in section 3.7, it was possible to achieve a good match with the recorded data using this relatively small range of net pay input assumptions. Achieving a simulation match to some of the recorded data, such as the arrival time of gas at surface and the pressure fluctuations recorded on the drill pipe after 21:30 hrs, proved to be quite sensitive to this narrow band of net pay input assumptions.

Constant net pay input assumptions were used for all of the simulations and it is acknowledged that varying net pay is probably more likely; this may explain some of the offsets between actual recorded data and the simulation results. However, the model results can be confidently utilized by the investigation team to test different well flow hypotheses when used in conjunction with other sources of information such as recorded real time data and witness accounts.

Conclusions:

The available evidence and simulation results strongly suggest that the initial flow path was through a leaking casing shoe and up through the inside of the casing. Using the input data collected by the investigation team, it was not possible to simulate flow through the outer annulus of the casing and match the recorded data and actual events witnessed. It was also clear that key points of reference such as a pressure increase during the sheen test could not be generated by flow through the outer annulus of the casing, the simulation shows a pressure decrease during this period of time rather than a pressure increase.

By using a net pay of between 13 ft and 16.5 ft and assuming flow via the casing shoe and through the production casing, a good simulation match for most of the actual events witnessed and data recorded can be achieved. Using a net pay of between 13 ft and 16.5 ft also seems realistic; it is less than 1/5th of the total productive sands in the well. The final simulation run which is based on these parameters, Case 7, is described in Section 3.7.8 of the report.

According to the simulations, the well became underbalanced at 20:52 hrs resulting in flow of hydrocarbons into the wellbore. Simulations show a total gain of around 40 bbls taken between 20:52 hrs and 21:08 hrs, a result supported by the gains calculated from recorded mud-pit data.

At 21:08 hrs, a sheen test was performed to verify that all the mud was displaced and the spacer had reached the surface. Between 21:08 hrs and 21:14 hrs, when the mud pumps were shutdown, the pressure on the drill pipe increased by more than 200 psi. This pressure increase could not be modeled by assuming flow through the outer annulus of the production casing, this model case showed a decrease in pressure rather than an increase. This 200 psi pressure increase could be modeled by assuming flow through the production casing shoe.

At approximately 21:10 hrs, during the sheen test, the flow was then routed to an overboard line bypassing the flow meters. From this point forward the flow from the well would have continued, but it appears that it went undetected by the rig crew.

At 21:14 hrs the mud pumps were restarted to displace the riser fully to seawater, this pumping operation continued until 21:30 hrs. The well would have continued to flow due to a significant amount of hydrocarbons already being in the wellbore causing a high under-balance with the reservoir pressure.

At 21:31 hrs, after the pumps had been shut down, there was a pressure increase in the well. This can be explained either by a mechanical closure downhole or the hydrostatic effect of mud flowing up the casing/drill pipe annulus. There is no indication that the rig crew had taken actions to close the BOP at that stage, therefore, it is thought that this first pressure increase was probably created by hydrostatic effects in the well rather than mechanical restrictions.

There was a pressure transient event between 21:36 hrs and 21:38 hrs with a very rapid pressure drop and then increase of over 1,000 psi. Simulations suggest that this was probably caused by bleeding through the drill pipe at surface. When trying to simulate this effect mechanically at the BOP by instantaneous opening and closing of a BOP element, the pressure transient effect created a much slower pressure response than was actually recorded during the event. The recorded sharp pressure response could be simulated by bleeding off the drill pipe pressure at surface.

The pressure increase during the last 8 minutes was likely due to the actions taken by the crew to close the BOP starting at approximately 21:41 hrs. Simulations indicate a more rapid increase in drill pipe pressure would have resulted if the well was shut-in and sealed at this time. However, the recorded data shows that this rapid pressure increase did not happen until 21:47 hrs. It is possible that the crew closed one of the annular preventers at 21:41 hrs but it failed to seal. Other evidence which supports this theory is as follows:

- Witness accounts indicate that well control action was not taken until about 21:41 hrs
- There were erosion marks on the retrieved drill pipe suggesting high velocity flow through an annular
- The simulations show that to create the recorded pressure response a BOP element would need to be almost fully closed (about a 99% closure).

At 21:47 hrs the rapid pressure increase in the drill pipe could be simulated by a BOP element fully sealing the well.

The last actual pressure recording on the drill pipe was 5,730 psi. According to the simulations, this pressure corresponds to a shut-in pressure with hydrocarbons in the wellbore up to the BOP and the drill pipe full of seawater.

If, as assumed, a BOP element was closed at seabed, the hydrocarbon flow to surface should have ceased at about 22:00 hrs. The investigation team have identified several potential causes explaining why the flow to surface continued and fueled the fire. These causes include, rig drift-off pulling the drill pipe through the BOP and breaking the BOP element seal and/or surface equipment failure creating a flow path through the drill pipe.

The volume of the drill pipe is 207 bbls, initially filled with water and some mud or hydrocarbons from the short bleed down. This volume would be unloaded in 2 minutes according to the simulations. After closing the BOP, the riser will still flow and unload due to the presence of hydrocarbons above the BOP. If the subsequent fire is fueled through the drill pipe, the flow rate through the drill pipe to surface based on an assumed net pay of 15 ft, is estimated to be 28,000 stb/d. If the subsequent fire is fueled through the riser, the flow rate through the riser to surface based on an assumed net pay of 15 ft, is estimated to be 41,000 stb/d.

It should be noted that these flow rates should not be considered as representative of the flow rates that occurred after the fire and explosion. There would have been different mechanical restrictions involved and probably different and varying levels of net pay open to flow. No work was completed in this report to consider flow rates from the well following the initial fire and explosion.

1. Background Information and Input Data

1.1 General

On April 20th 2010, a fire and explosion occurred onboard the Deepwater Horizon rig while it was working on the Macondo well prospect offshore Louisiana. The rig had cemented the casing and complications occurred during and after performing a negative test (standard procedure to test the cement job). Explosions occurred with subsequent fire and uncontrolled flow of hydrocarbons and a total loss of well control. The rig sank April 22nd.

An investigation team was established to evaluate the causes of the accident. Add wellflow was asked to contribute to the investigation by completing dynamic analysis, simulations and evaluations, and this report summarizes the work performed.

1.2 Well location

The well is located on the Macondo prospect situated on Mississippi Canyon block 252 (MC 252), offshore Louisiana, Gulf of Mexico, 52 miles southeast of the Louisiana port of Venice.

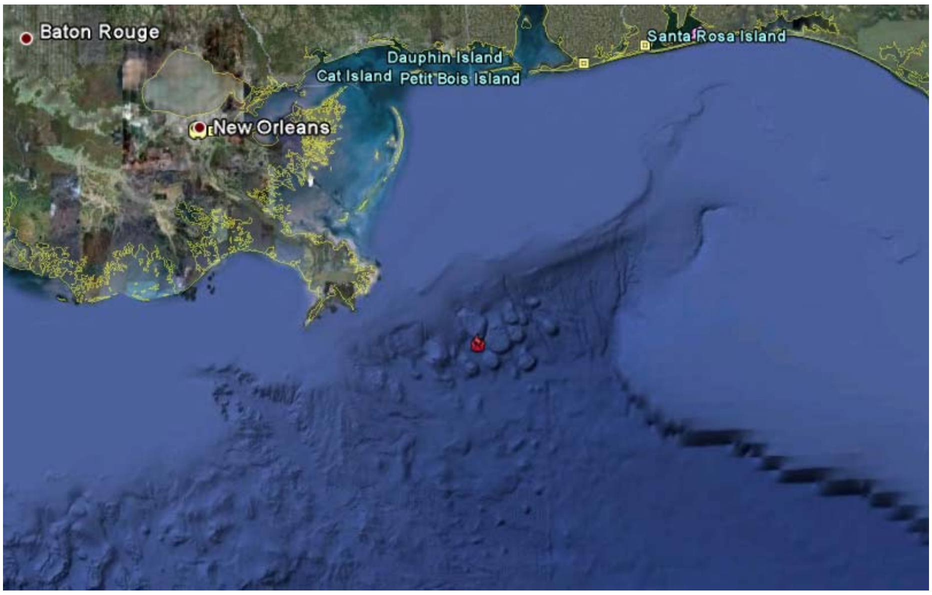


Figure 1.1: Field location

1.3 Water Depth

The water depth at the spud location is 4,992 ft MSL.

1.4 Drilling Rig

The Deepwater Horizon was a dynamic positioned semi-submersible drilling unit capable of operating in harsh environments and water depths over 9,000 ft using 18 ¾" 15,000 psi BOP and 21" OD (19 ½" ID) marine riser. The air gap (RKB – MSL) is 75 ft.

Figure 1.2: The Transocean Deepwater Horizon Rig

1.5 Reservoir fluid

An analysis of the specified reservoir fluid composition reveals an under-saturated oil with a bubble point at 6,500 psi at reservoir temperature and a GOR of 2,824 scf/stb. The reservoir fluid composition has been used to generate all the thermodynamical properties required for the analyses, but is not included in this report.

1.6 Mud properties

The dynamic simulations reproduce the trends shown by the data logs. For operations involving flow of the spacer (a combination of Form-A-Set and Form-A-Squeeze), the pressure drop in the system was higher than what was estimated by the model. A non-Newtonian Bingham viscosity model was used but could still not reproduce the viscous behavior of the spacer. This effect was compensated by introducing additional pressure drop at the outlet of the wellbore. Rheology tests performed after the incident using a viscometer showed off scale readings and indicated very high viscosity for the combined Form-A-Set and Form-A-Squeeze spacer. This highly viscous non-Newtonian fluid is believed to be causing the discrepancy in simulated pressures versus actual recorded data during the period that the spacer is still in the riser. Table 1.1 shows the numbers used for the spacer and for the 14 ppg synthetic oil based mud.

Table 1.1: Rheology data for synthetic oil based mud and the combined Form-A-Set and Form-A-Squeeze)spacer

	SOBM	**Spacer**
Density, ppg	**14**	**16**
Plastic viscosity, cP	28	324
Yield Point, lbf/100 ft²	14	34
10 sec gel, lbf/100 ft²	14	31
10 min gel, lbf/100 ft²	23	38

1.7 Reservoir data

The main reservoir in the Macondo well consists of two oil bearing sands, the Upper M56 and the Lower M56. Both sands have a pore pressure of 12.6 ppg. The top of the Upper M56 is at 18,086 ft TVD RKB and only a few feet separate the upper and the lower sands. The reservoir sands are very prolific. Based on 300 mD and 86 ft net pay, the inflow performance curve indicates a productivity index of 49 stb/d/psi for pressures above the bubble point pressure. This contributes to a fast unloading of the well when it is left open to flow in an underbalanced condition. For example, a drawdown of only 1,000 psi results in an influx of 73 bpm of oil from the reservoir into the wellbore. This is equivalent to a rate of 34 stb/m at surface conditions, the oil formation volume factor is 2.14 bbl/stb. It is probable that the sands will be restricted by the cement and that the resulting reservoir exposure is less than the total reservoir thickness. A net pay of between 13 ft to 16.5 ft was used in the final simulations represented in Case 7 (see Section 3.7.8) and this gave a good match with the recorded data.

1.8 Pore and fracture pressure profile

The pore and fracture pressure profiles are shown in Figure 1.3 and Figure 1.4.

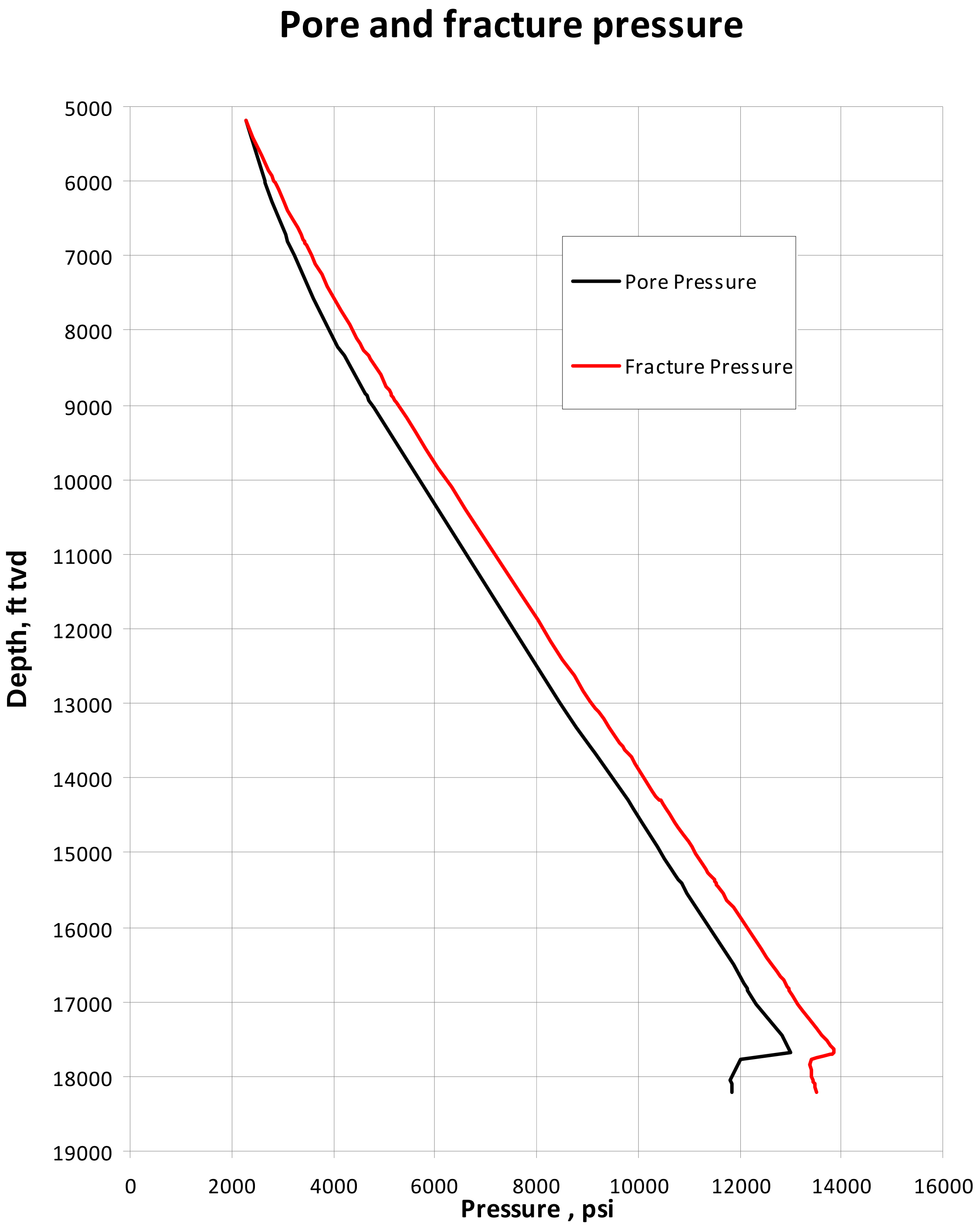


Figure 1.3: Pore and fracture pressure profile

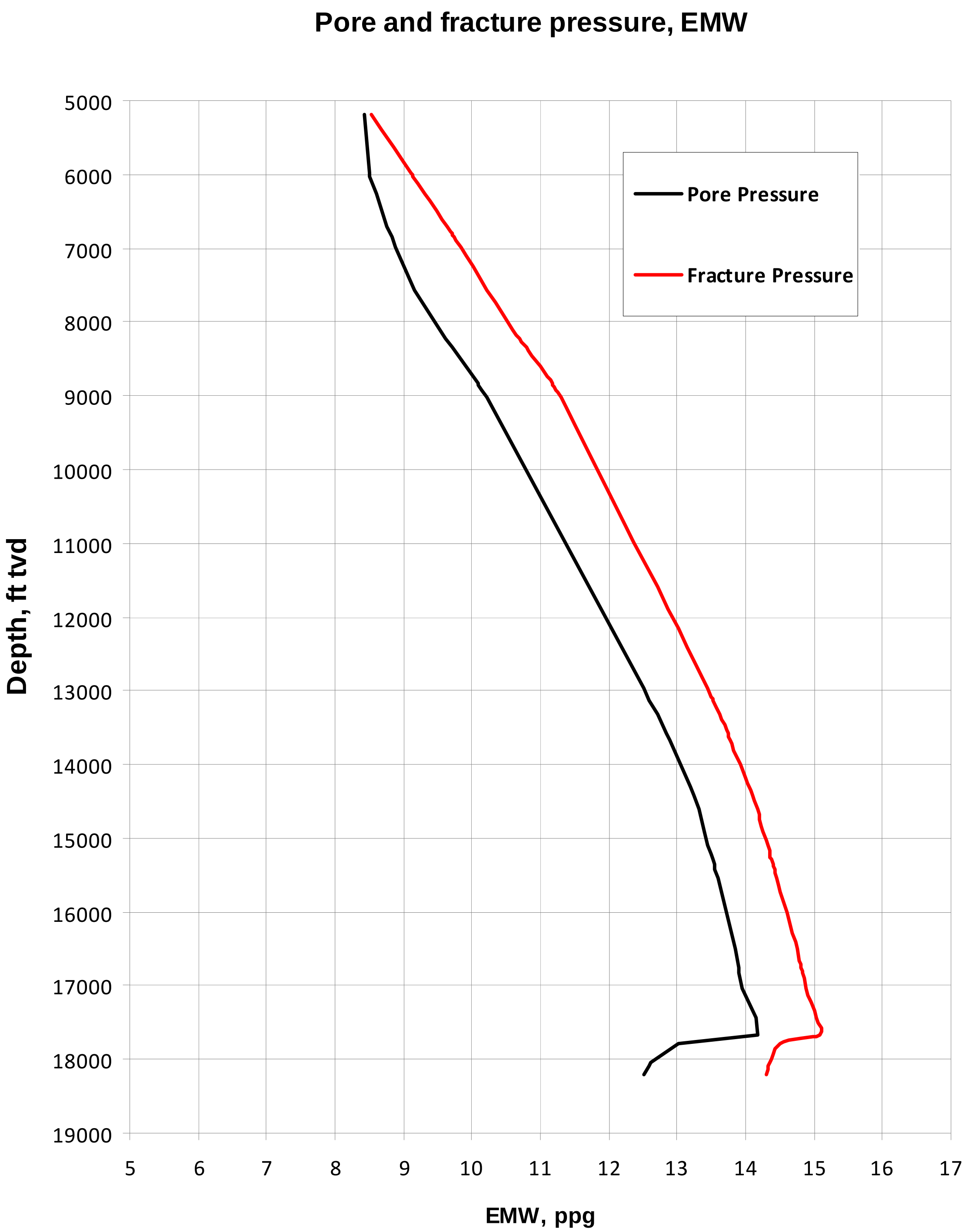


Figure 1.4: Pore and fracture pressure expressed in equivalent mud weight, EMW

1.9 Temperature profile

The temperature profile is shown in Figure 1.5.

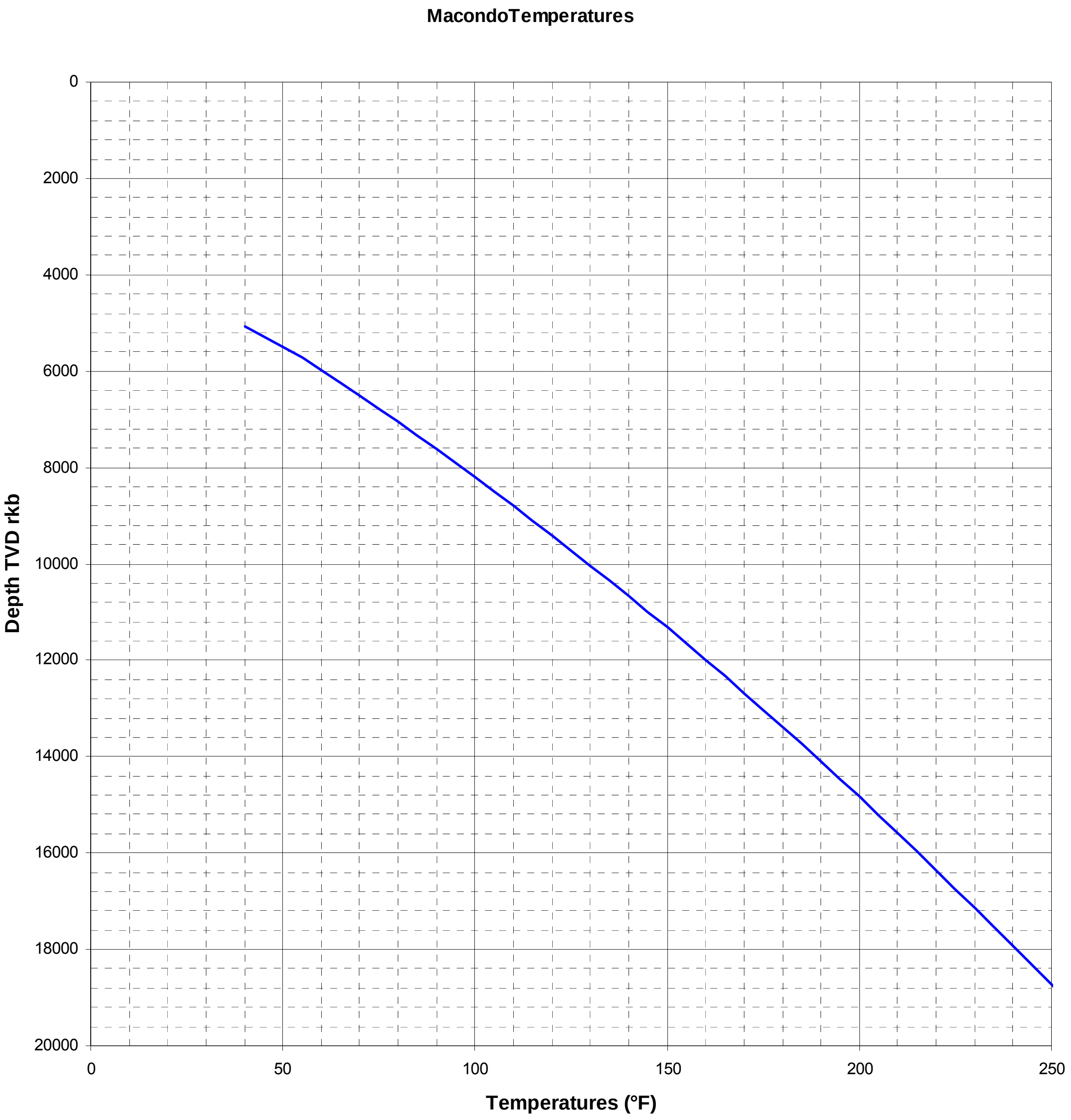


Figure 1.5: Temperature profile

1.10 Well configuration and casing design

The pipe dimensions for the outer casing strings are listed in Table 1.2; dimensions for the inner casing strings are listed in Table 1.3; the dimensions for the drill pipe are listed in Table 1.4. The total volume inside the casing up to seabed is 746 bbl. The volume in the outer annulus is 1,180 bbl. The volume in the annulus between the riser and the drill pipe is 1,640 bbl. The volume inside the drill pipe is 207 bbl. Figure 1.6 shows a schematic of the well with depths at scale while Figure 1.7 shows the wellbore capacities.

Table 1.2: Outer casing strings

	Weight lb/ft	**OD in**	**ID in**	**Top ft**	**Bottom ft**	**Length ft**	**Capacity bbl/ft**
Choke/Kill			4.5	0	5067	5067	0.019672
Riser		21	19.5	0	5001	5001	0.369390
BOP			18.75	5001	5054	53	0.341522
Wellhead			18.5	5054	5057	3	0.332475
22" Casing		22	18.375	5057	5227	170	0.327998
16 " Casing	97	16	14.85	5227	11153	5926	0.214224
13 ⅜" Liner	88.2	13.375	12.375	11153	12803	1650	0.148767
11 ⅞" Liner	71.8	11.875	10.711	12803	14759	1956	0.111449
9 ⅞" Liner	62.8	9.875	8.625	14759	17157	2398	0.072266
Open Hole			9.875	17157	18130	973	0.094731
Rat Hole			8.5	18130	18360	230	0.070187

Table 1.3: Inner casing strings (cemented)

	Weight lb/ft	**OD In**	**ID In**	**Top ft**	**Bottom ft**	**Length ft**	**Capacity bbl/ft**
9 ⅞" x 7" Tapered Csg	62.8	9.875	8.625	5067	12484	7417	0.072266
9 ⅞" x 7" Tapered Csg	32	7	6.094	12484	18303	5819	0.036076

Table 1.4: Drill pipe dimensions

	Weight lb/ft	**OD in**	**ID in**	**Top ft**	**Bottom ft**	**Length ft**	**Capacity bbl/ft**
6 ⅝" DP	32	6.625	5.426	0	4177	4177	0.028601
5 ½" DP	21.9	5.5	4.78	4177	7567	3390	0.022196
3 ½" DP	9.3	3.5	2.992	7567	8367	800	0.008696

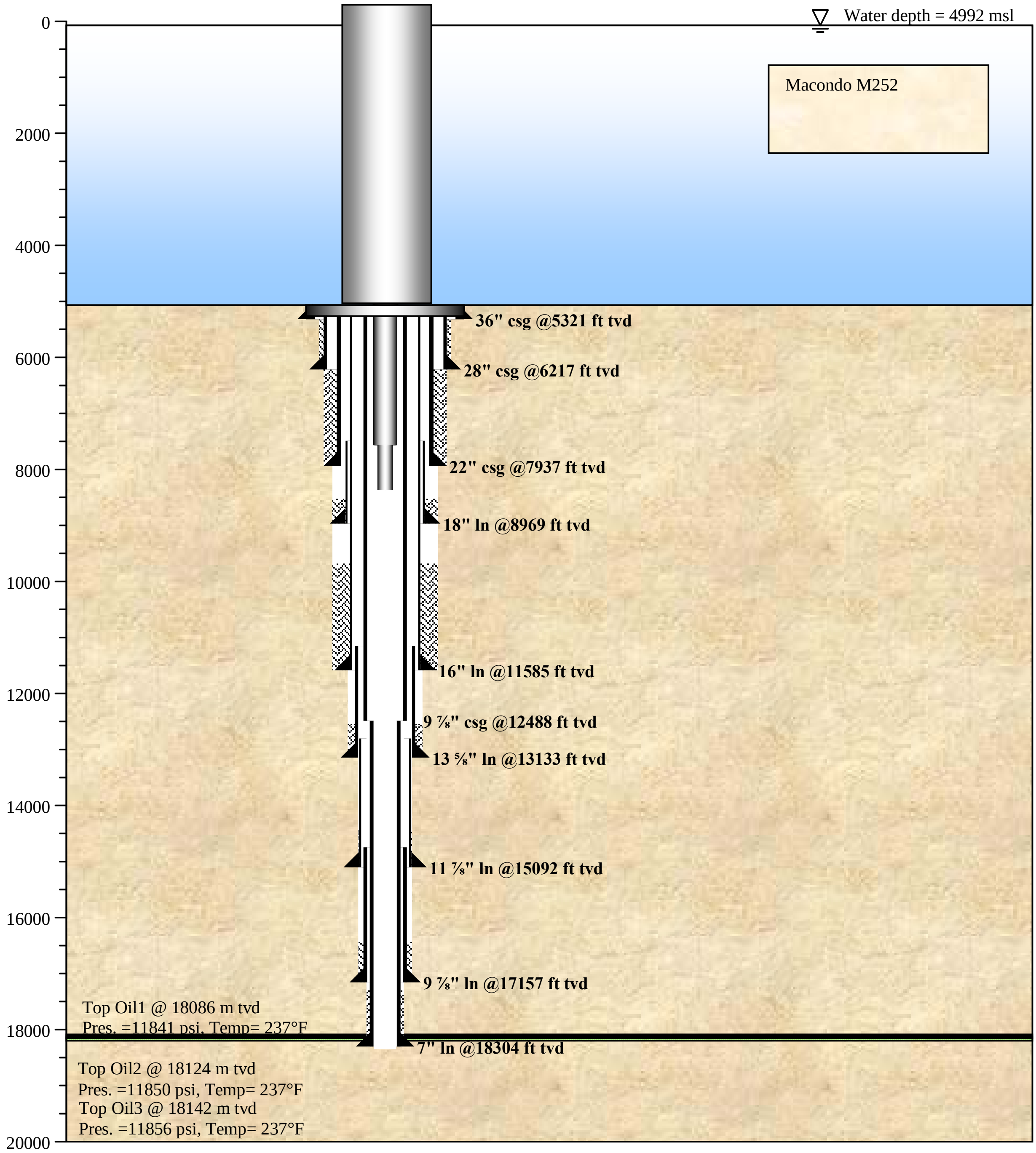

0
2000
4000
6000
8000
10000
12000
14000
16000
18000
20000
Water depth = 4992 msl
Macondo M252
36" csg @5321 ft tvd
28" csg @6217 ft tvd
22" csg @7937 ft tvd
18" ln @8969 ft tvd
16" ln @11585 ft tvd
9 ⅞" csg @12488 ft tvd
13 ⅝" ln @13133 ft tvd
11 ⅞" ln @15092 ft tvd
9 ⅞" ln @17157 ft tvd
7" ln @18304 ft tvd
Top Oil1 @ 18086 m tvd
Pres. =11841 psi, Temp= 237°F
Top Oil2 @ 18124 m tvd
Pres. =11850 psi, Temp= 237°F
Top Oil3 @ 18142 m tvd
Pres. =11856 psi, Temp= 237°F

Figure 1.6: Well schematic, TVD drawn to scale

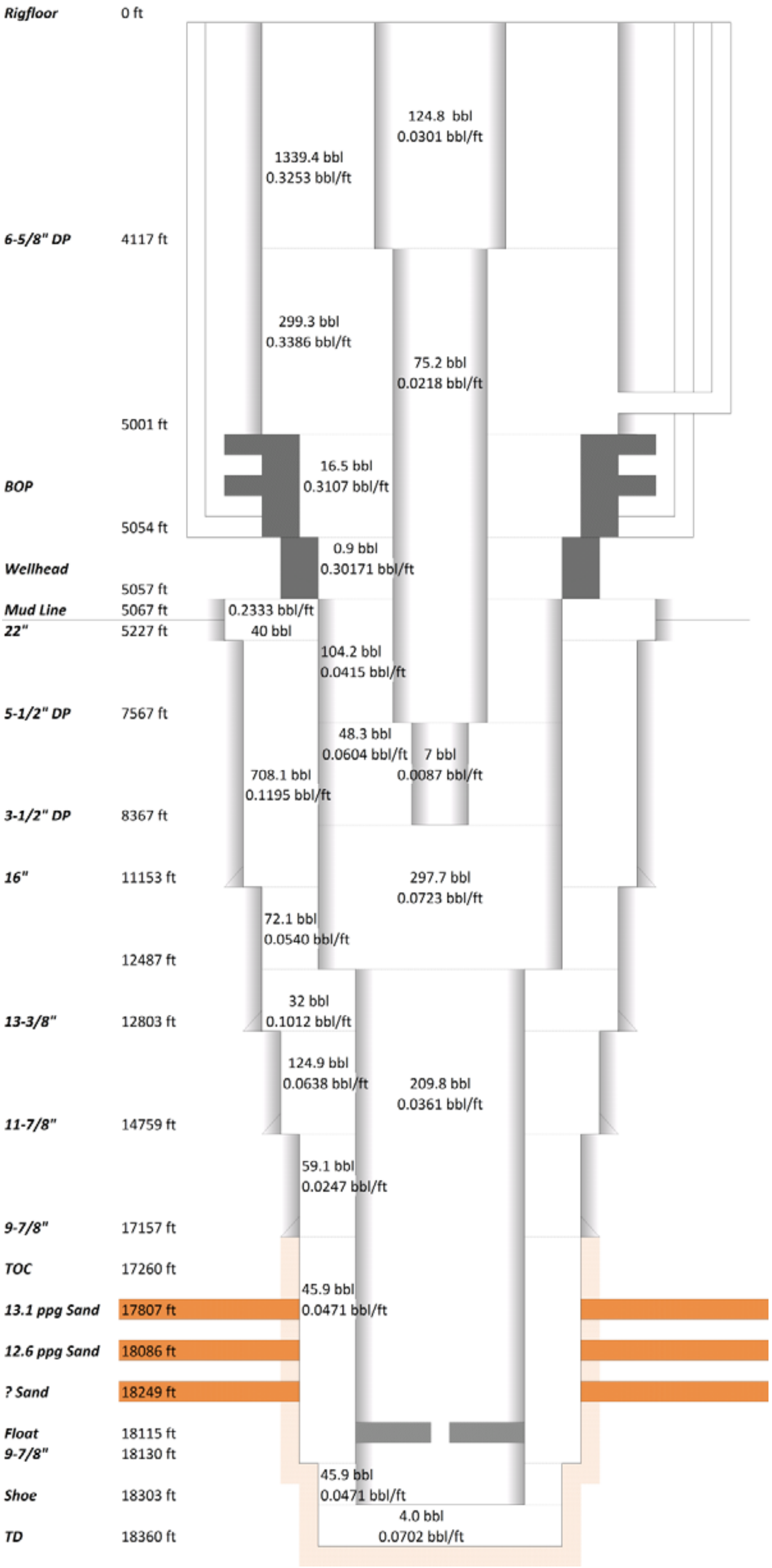

Rigfloor
0 ft
124.8 bbl
0.0301 bbl/ft
1339.4 bbl
0.3253 bbl/ft
6-5/8" DP
4117 ft
299.3 bbl
0.3386 bbl/ft
75.2 bbl
0.0218 bbl/ft
5001 ft
16.5 bbl
0.3107 bbl/ft
BOP
5054 ft
0.9 bbl
0.30171 bbl/ft
Wellhead
5057 ft
Mud Line
5067 ft
0.2333 bbl/ft
22"
5227 ft
40 bbl
104.2 bbl
0.0415 bbl/ft
5-1/2" DP
7567 ft
48.3 bbl
0.0604 bbl/ft
7 bbl
0.0087 bbl/ft
708.1 bbl
0.1195 bbl/ft
3-1/2" DP
8367 ft
16"
11153 ft
297.7 bbl
0.0723 bbl/ft
72.1 bbl
0.0540 bbl/ft
12487 ft
32 bbl
0.1012 bbl/ft
13-3/8"
12803 ft
124.9 bbl
0.0638 bbl/ft
209.8 bbl
0.0361 bbl/ft
11-7/8"
14759 ft
59.1 bbl
0.0247 bbl/ft
9-7/8"
17157 ft
TOC
17260 ft
45.9 bbl
0.0471 bbl/ft
13.1 ppg Sand
17807 ft
12.6 ppg Sand
18086 ft
? Sand
18249 ft
Float
18115 ft
9-7/8"
18130 ft
45.9 bbl
0.0471 bbl/ft
Shoe
18303 ft
4.0 bbl
0.0702 bbl/ft
TD
18360 ft

Figure 1.7: Well schematic showing volume capacities

2. Events leading up the well control incident

The well was drilled to target depth (TD) at 18,350 ft TVD and the 9 ⅞ x 7" production casing was run and cemented. It took nine attempts to convert the float equipment before it appeared to have converted and the cementing could start. 14 ppg mud was in the wellbore.

After cementing, the 9 ⅞" seal assembly was set and tested to 6,500 psi followed by a casing test to 2,600 psi. It took 6.7 bbls to pressurize the casing from 0 to 2,600 psi.

A tapered drill pipe (6 ⅝" – 5 ½" – 3 ½") was run to 8,367 ft before the negative test. The boost, choke and kill lines were displaced to seawater. A batch of 424 bbl of 16 ppg spacer and 30 bbl of fresh water was pumped followed by 352 bbl of seawater. The plan was to pump the spacer just above the BOP stack; because the BOP annular leaked the spacer was drawn down across the BOP during the subsequent bleed offs. The pressure on the drill pipe was 2,400 psi after the water was pumped. The annular preventer was then closed.

The pressure was bled down from 2,400 psi to 1,200 psi through the drill pipe and larger than predicted bleed back volumes were observed. The bleed down was continued, but the pressure did not decrease below 250 psi, and the well was subsequently shut in. Witness accounts vary with respect to bleed back volumes. According to witness statements, the riser was filled up with 50 – 60 bbl during this period. After the bleed down, the pressure increased to 1,250 psi during a period of 7 minutes.

During further attempts to set-up for the negative test additional volumes were recovered from the well; there is uncertainty in the exact volume of fluid that was bled from the well compared with how much fluid was added when topping up the riser. The best estimate of the investigation team is that between 60 - 85 bbls of fluid were bled from the well and between 50 - 60 bbls of fluid were added to the well during the riser top-up. When including the effect of fluid compressibility it is possible that an influx of anything from between 0 to 20 bbls of hydrocarbon occurred during the negative test.

Following the bleed downs whilst setting up for the negative test, the pressure on the drill pipe gradually increased from 200 psi to 1,400 psi over a 30 minutes period, the pressure stabilized at 18:35 hrs (see Figure 2.1). At 20:02 hrs, the pumps were started to displace the mud and spacer with seawater. The pumps were shut down for a sheen test at 21:08 hrs and the test indicated that the fluids could be discharged overboard. The pumping resumed after the sheen test was completed at approximately 21:14 hrs and continued until 21:30 hrs when the pumps were shut down.

After 21:31 hrs there was a pressure increase followed by a rapid pressure drop and increase between 21:36 hrs and 21:38 hrs. The pressure then dropped followed by a second pressure increase at approximately 21:41 hrs and finally by a rapid increase at approximately 21:47 hrs. The data stream ends at 21:49 hrs. The simulations attempted to provide an explanation for the causes of these pressure fluctuations.

Witness accounts suggest that it is unlikely that any action was taken to shut-in the well with a BOP element before 21:41 hrs, if so, the pressure fluctuations before 21:41 hrs cannot be explained by simulating the closure of a BOP element.

Witness accounts also suggest that mud was seen flowing (cascading) off the rig floor and then up through the derrick before the rig crew diverted to the mud gas separator (MGS). Mud was then seen raining down from the derrick, most likely due to an overfilled MGS and vent line. Simulations were conducted to replicate this sequence of events to allow the investigation team to understand probable surface flow rates and surface equipment operating pressures. These simulations supported the investigation team in assessing surface equipment failure modes and in developing a gas dispersion model.

At approximately 21:49 hrs, the first explosion occurred and the lights went out almost simultaneously. Approximately 10 seconds later, per witness accounts, a second explosion occurred. These timings indicate that there were significant gas volumes at surface at this time and the simulations needed to be able to replicate this reality.

The following plots show the drill pipe pressure recorded from 16:00 hrs till the explosions occurred at 21:49 hrs.

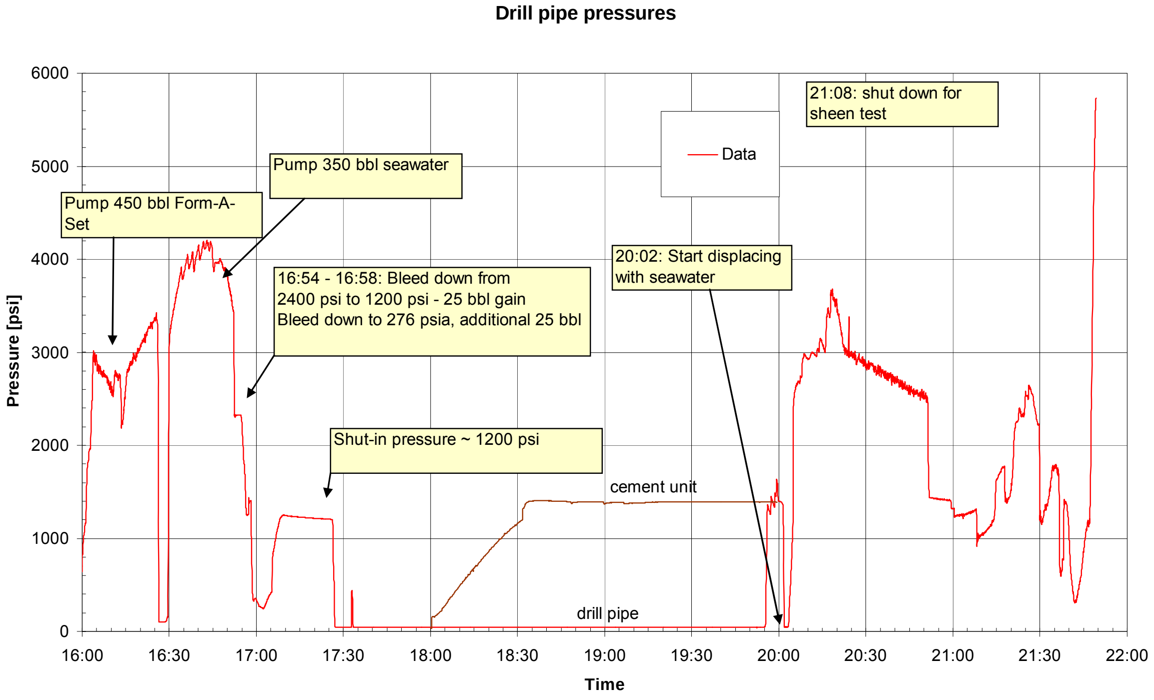


Figure 2.1: Recorded drill pipe pressures from 16:00 hrs to 21:49 hrs

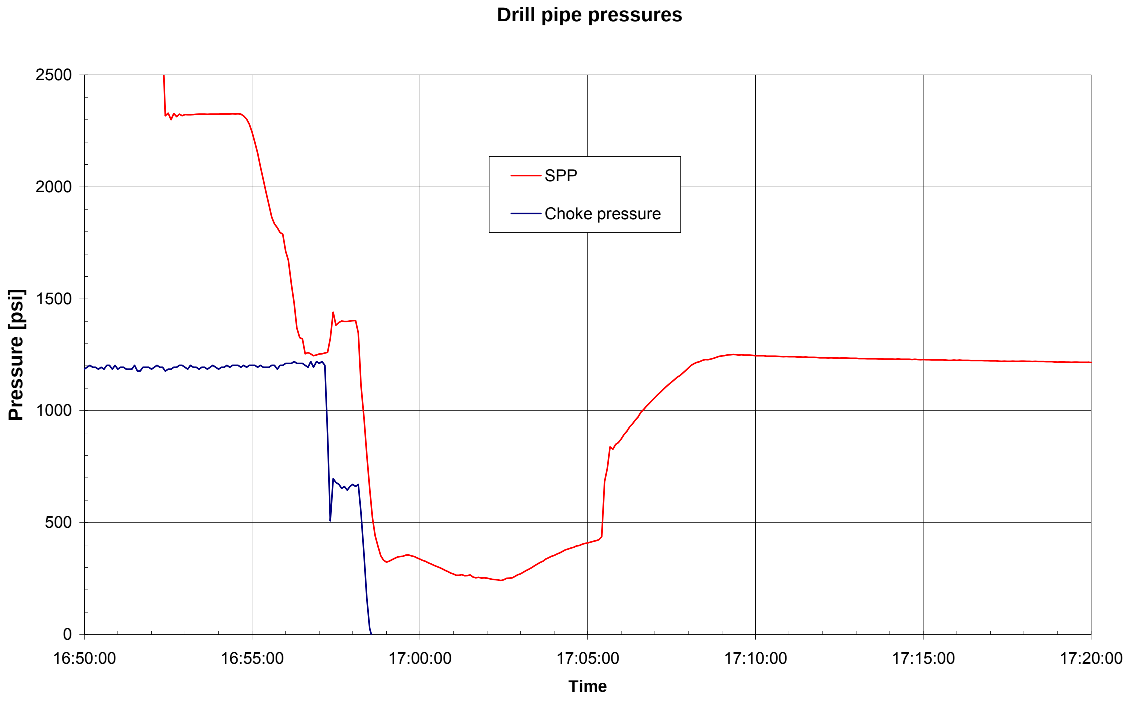


Figure 2.2: Recorded drill pipe pressures from 16:50 hrs to 17:20 hrs

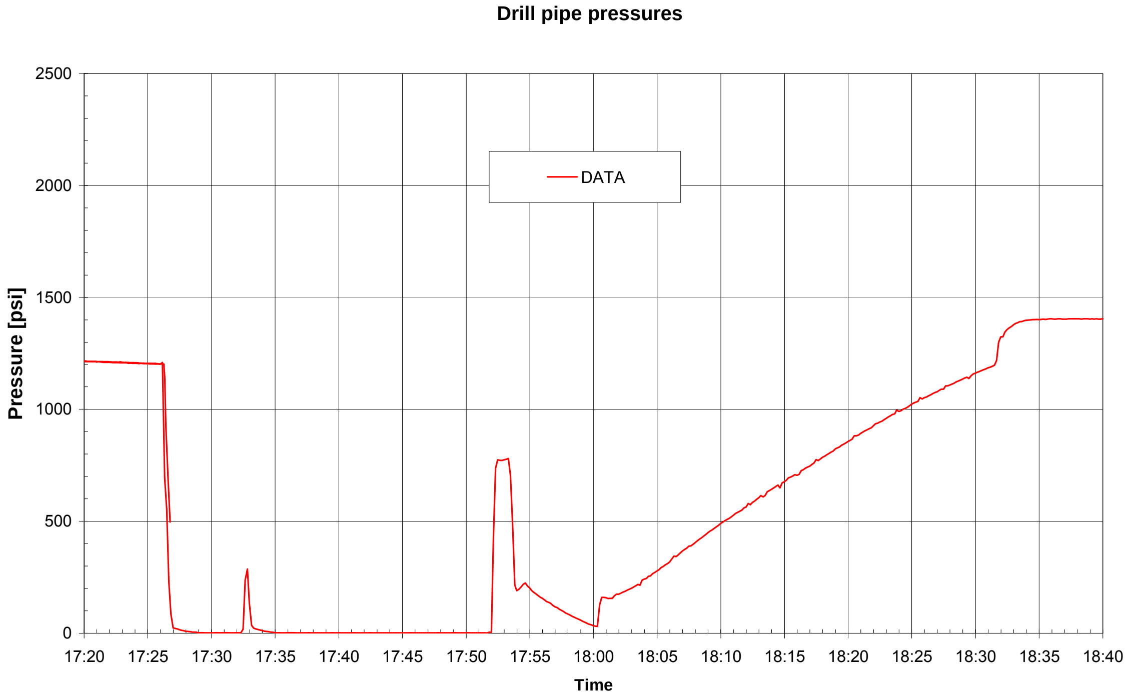


Figure 2.3: Recorded drill pipe pressures from 17:20 hrs to 18:40 hrs

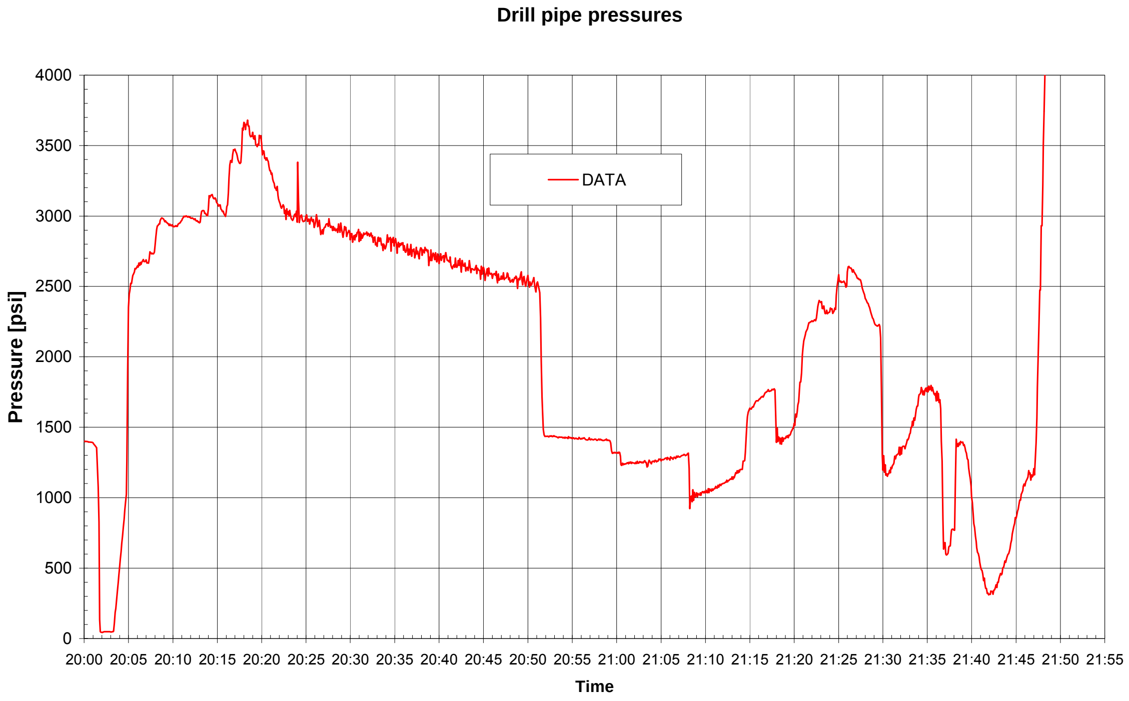


Figure 2.4: Recorded drill pipe pressures from 20:00 hrs to 21:49 hrs

3. Results

3.1 Oil density with pressure and temperature

The reservoir fluid is an under-saturated oil with a bubble point at 6,500 psi at reservoir temperature. The density of the oil phase will decrease with decreasing pressure (see Figure 3.1) and increase with decreasing temperature (see Figure 3.2). These two effects will almost balance each other when an oil kick is taken and slowly migrates towards the surface through the mud. The resulting volume expansion is almost zero (see Figure 3.3).

This type of density behavior would challenge the detection of any small oil kick (small influx of hydrocarbons). After an oil kick (assuming there was no continued influx) there would be no significant volume gain until the hydrocarbon is just below the BOP. Just below the BOP, with 14 ppg mud in the wellbore, gas would start to break-out and create further gains at surface. The crew would have less time to react to an isolated kick, and once a well control problem is confirmed, a late detection can mean that gas is already inside the riser before the crew recognizes there is a well control issue and closes the BOP. This behavior is different from a gas kick, but still not uncommon for deepwater drilling operations. Awareness and knowledge of these mechanisms is important.

However, it is noted that the Macondo accident was not caused by a small oil kick but by a continuous influx of hydrocarbons in the wellbore resulting in significant gained volumes that should have been detectable.

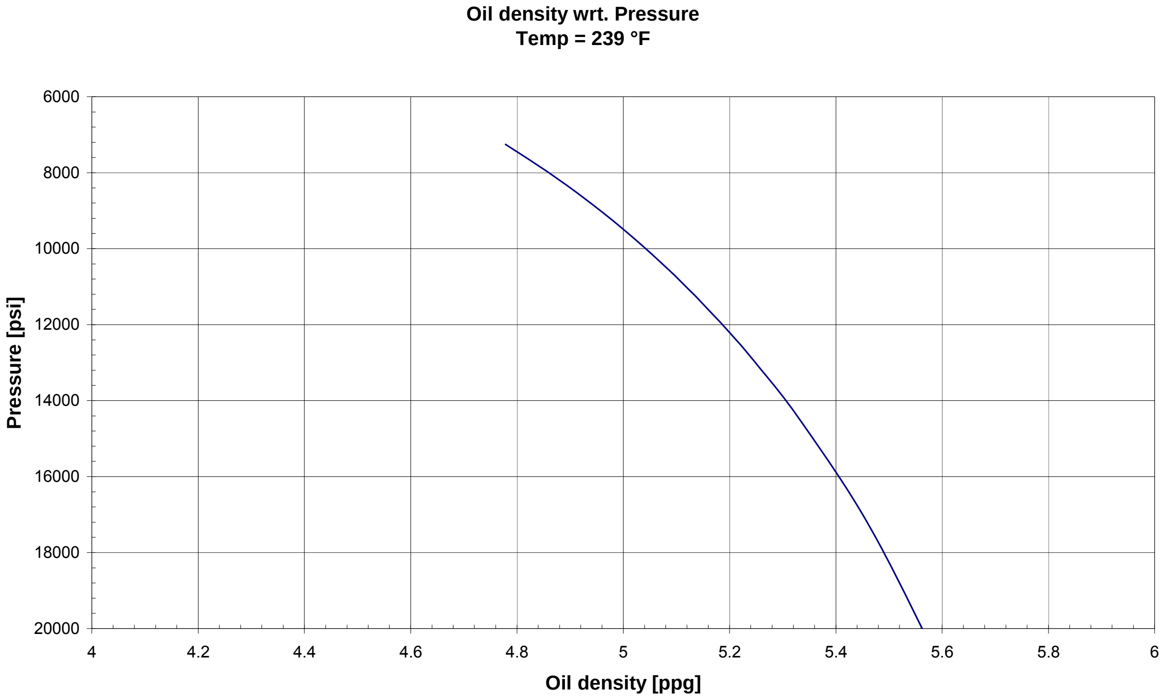


Figure 3.1: Oil density versus pressure for temperature = 239 °F

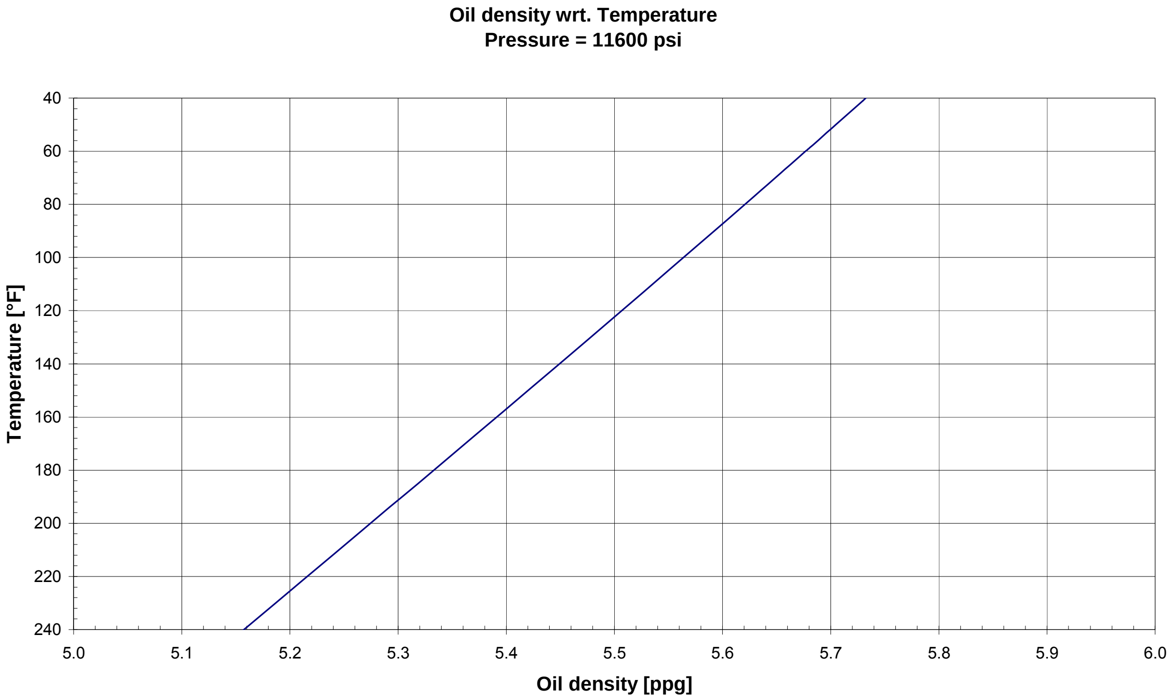


Figure 3.2: Oil density versus temperature for pressure = 11,600 psia

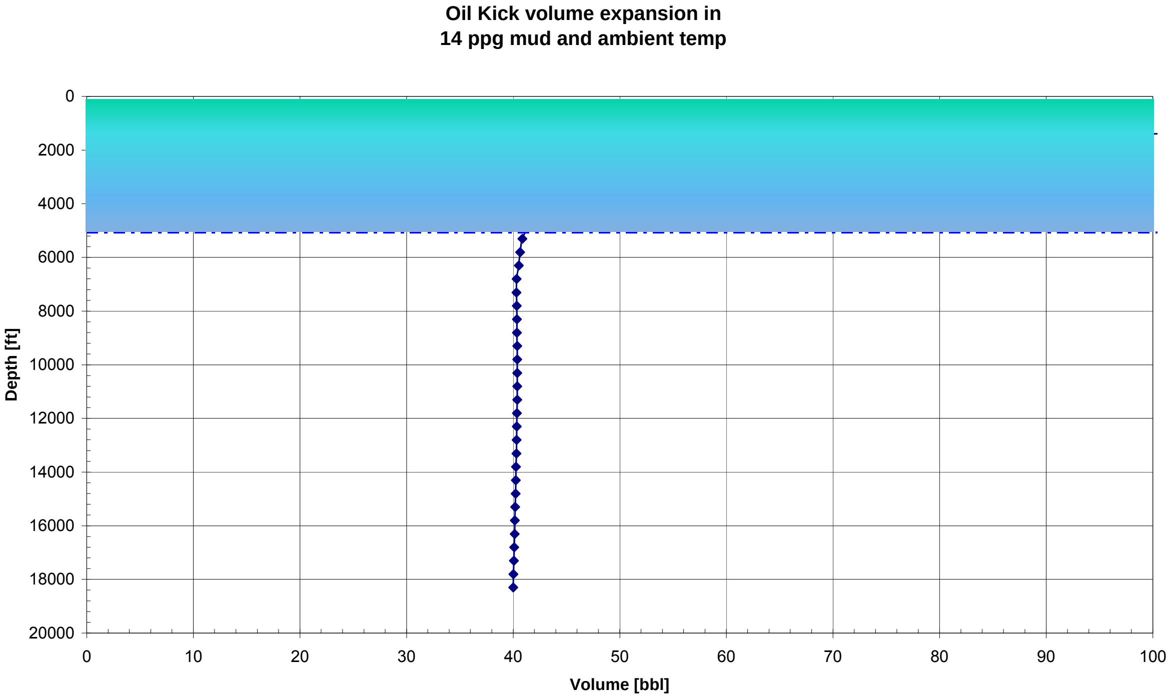


Figure 3.3: Volume expansion for a 40 bbl oil kick migrating to surface through 14 ppg mud

3.2 Inflow performance

The 12.6 ppg pressured oil sands have an estimated average permeability of 300 mD over 86 ft of net pay. This, together with the fluid properties, will result in a productivity index of 49 stb/d/psi from reservoir pressure down to the bubble point pressure at 6,500 psi. For pressures below the bubble point, gas will flash out of solution, and turbulent skin effects will limit the flow potential. Figure 3.4 shows the resulting inflow performance based on 4 ft reservoir exposure and 86 ft reservoir exposure. As can be seen, the reservoir is very prolific.

Due to the high oil formation volume factor (shrinkage factor) of 2.14 Rbbl/Stb, the volumetric inflow rate at reservoir conditions is more than twice as high as those reported at standard conditions. Figure 3.5 shows the inflow performance at reservoir conditions (in-situ conditions).

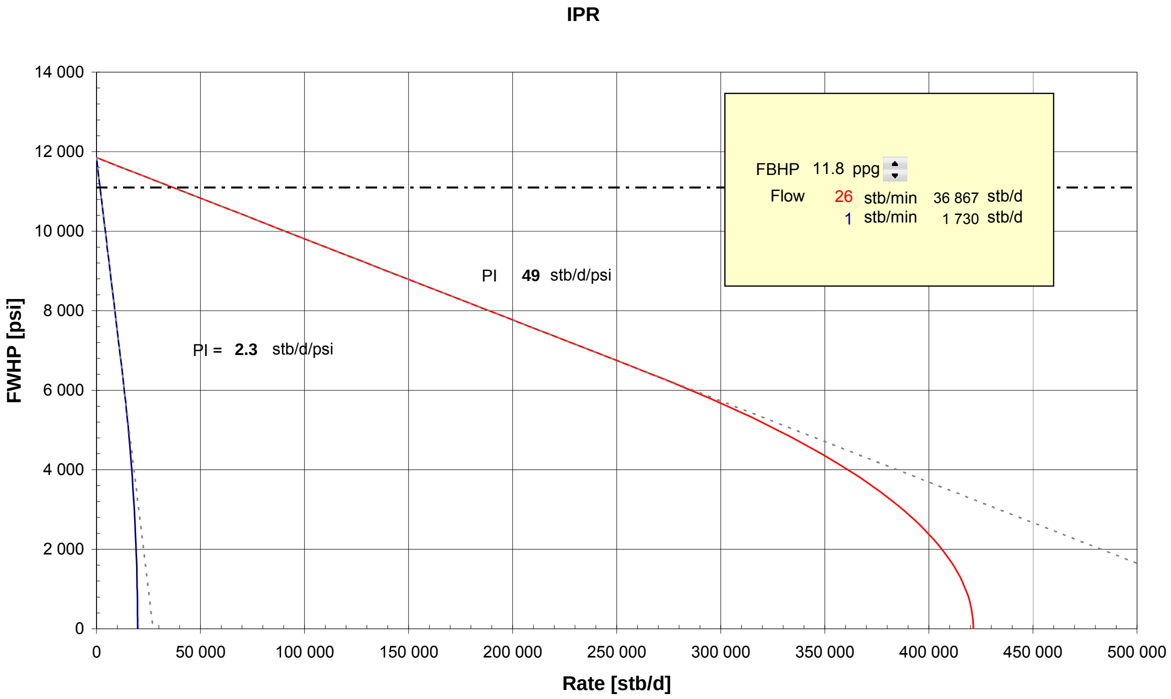


Figure 3.4: Inflow performance curves at standard conditions based on 4 ft and 86 ft of 300 mD sand

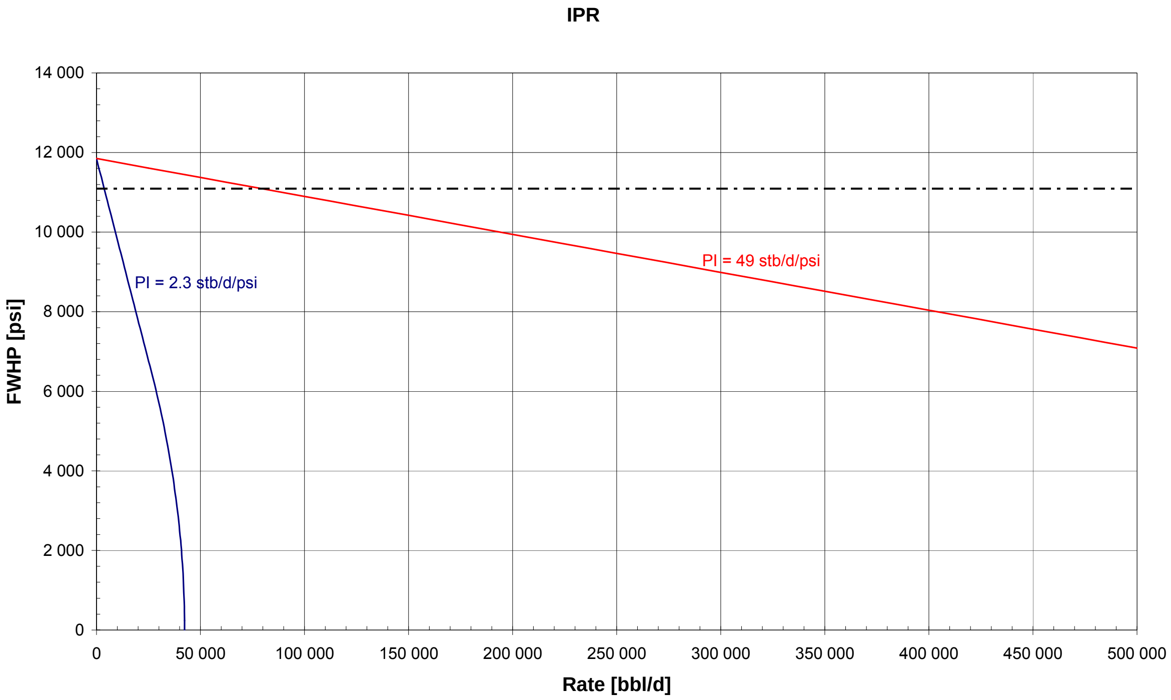


Figure 3.5: Inflow performance curves at reservoir conditions based on 4 ft and 86 ft of 300 mD sand

3.3 Compressibility of the 14 ppg mud

Two observations are made with respect to the compressibility of the 14 ppg mud. The first was during the attempts to convert the float on April 19th between 14:30 hrs and 17:30 hrs. It took nine attempts before the float was converted, the associated pressures and volumes were recorded (see Table 3.1).

Table 3.1: Float conversion attempts

Attempt No	**Total volume [bbl]**	**From [psi]**	**To [psi]**	**Volume [bbl]**	**Comp. [1/psi]**
#4	886	0	2000	6.7	3.78E-06
#5	886	0	2000	6.6	3.72E-06
#7	886	0	2250	7.3	3.66E-06
#8	886	0	2500	7.8	3.52E-06
Average					**3.67E-06**

In addition to these attempts, a casing pressure test was performed April 20th between 11:06 hrs and 11:17 hrs (see Table 3.2).

Table 3.2: Casing pressure test

Test	Total volume [bbl]	From [psi]	To [psi]	Volume [bbl]	Comp. [1/psi]
Casing	758	234	2617	6.1	3.13E-06

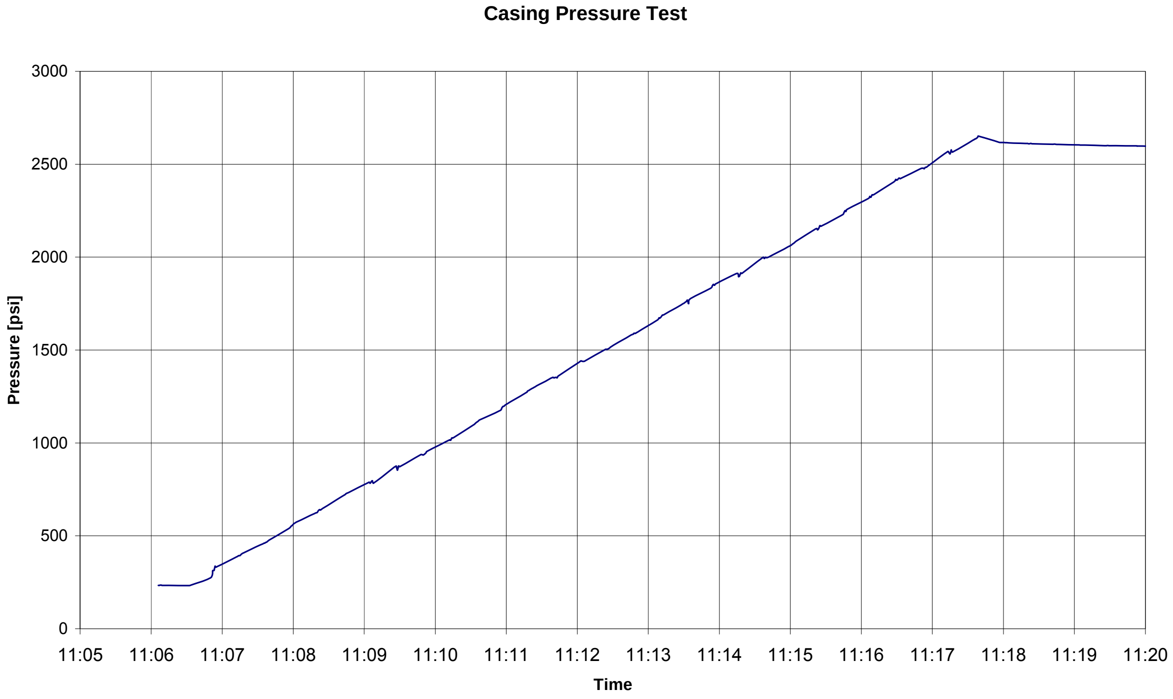


Figure 3.6: Casing pressure test from 234 psi to 2617 psi (6.0 bbl)

The compressibility is a measure of how much incremental fluid is required to pressurize fluid contained in a fixed volume by a certain amount of psi.

$$k = \frac{\partial V}{V \cdot \partial P}$$

The outer annulus measures approximately 1,100 bbl, and by using the average number from the float conversion attempts (3.67E-06), approximately 10 bbl will be expected to be bled back from this volume when decreasing the pressure from 2,400 to 250 psi.

The reported gains (60 – 85 bbls) during the negative test bleed downs were higher than what could be expected due to the compressibility of the mud. Some of this discrepancy (50 – 60 bbls) was explained by a leaking BOP annular and some can be explained by the compressibility of the mud. It is possible that an influx of between 0 to 20 bbls of hydrocarbon occurred during the negative test bleed downs.

3.4 Blowout potentials

Estimation of the well's flowing potential is important for the determination of the events leading up to the explosion. This analysis of the blowout potential attempts to simulate the conditions around the time of the incident and does not estimate the potential flow rate after the incident, which would depend on additional unknown factors which were not considered, such as restrictions in the BOP, limited reservoir exposure etc. The estimated blowout potential for several different scenarios are listed in Table 3.3, all based on comingled flow from the 12.6 ppg oil reservoirs with an average permeability of 300 mD. It is assumed that the flow is exiting through both the riser and through the drill pipe without any restrictions.

The highest flow potential is through the production casing. The outer annulus of the production casing has some narrow sections (between the 9 ⅞" casing and the 7" casing) and this will create more frictional forces and higher pressure drop.

Table 3.4 (flow at surface) and Table 3.5 (flow at seabed) show the distribution of flow between the drill pipe and the riser for the scenario of flow through the production casing. In addition, the total flow potential based on a blocked drill pipe and flow in the riser only, and a sealed BOP and flow in the drill pipe only, are included.

Figure 3.7 shows flow rates in stb/d for flow through the production casing shoe versus increasing net pay, it is assumed that flow is unrestricted and flowing through both the riser and the drill pipe simultaneously. There are two plots on the chart, one showing the flow rate to surface and the other showing the flow rate at the seabed.

Figure 3.8 shows flow rates in stb/d for flow through the production casing shoe versus increasing net pay, it is assumed that flow is unrestricted and flowing just through the drill pipe. There are two plots on the chart, one showing the flow rate to surface and the other showing the flow rate at the seabed.

Simulations were also performed for the blowouts to seabed with restrictions in the BOP. By including a restriction resulting in a flowing wellhead pressure of 3800 psi, the flow potential decrease by approximately 10 %. From 61 000 stb/d to 54 000 stb/d inside the casing using 86 ft pay zone and assuming flow through the casing shoe. By using a wellhead pressure of 3000 psi, the flow rate reduces to 58 000 stb/d. See Figure 3.9.

Table 3.3: Blowout potential versus flow path, net pay and exit point

Flow path	**Outer annulus [stb/d]**		**Casing [stb/d]**	
Exit point	**Surface**	**Seabed**	**Surface**	**Seabed**
4 ft net pay	17 500	14 000	18 000	15 000
86 ft net pay	47 000	43 000	68 000	67 000

Table 3.4: Distribution of flow for casing scenario to surface

Flow path	**Casing [stb/d]**				
Exit point	**Drill pipe**	**Riser**	**Total**	**Only Riser**	**Only DP**
4 ft net pay	4 500	13 500	18 000	18 000	15 000
86 ft net pay	21 000	47 000	68 000	61 000	36 000

Table 3.5: Distribution of flow for casing scenario to seabed

Flow path	**Casing [stb/d]**				
Exit point	**Drill pipe**	**Riser**	**Total**	**Only Riser**	**Only DP**
4 ft net pay	3 800	11 200	15 000	15 000	13 500
86 ft net pay	19 500	47 500	67 000	61 000	40 000

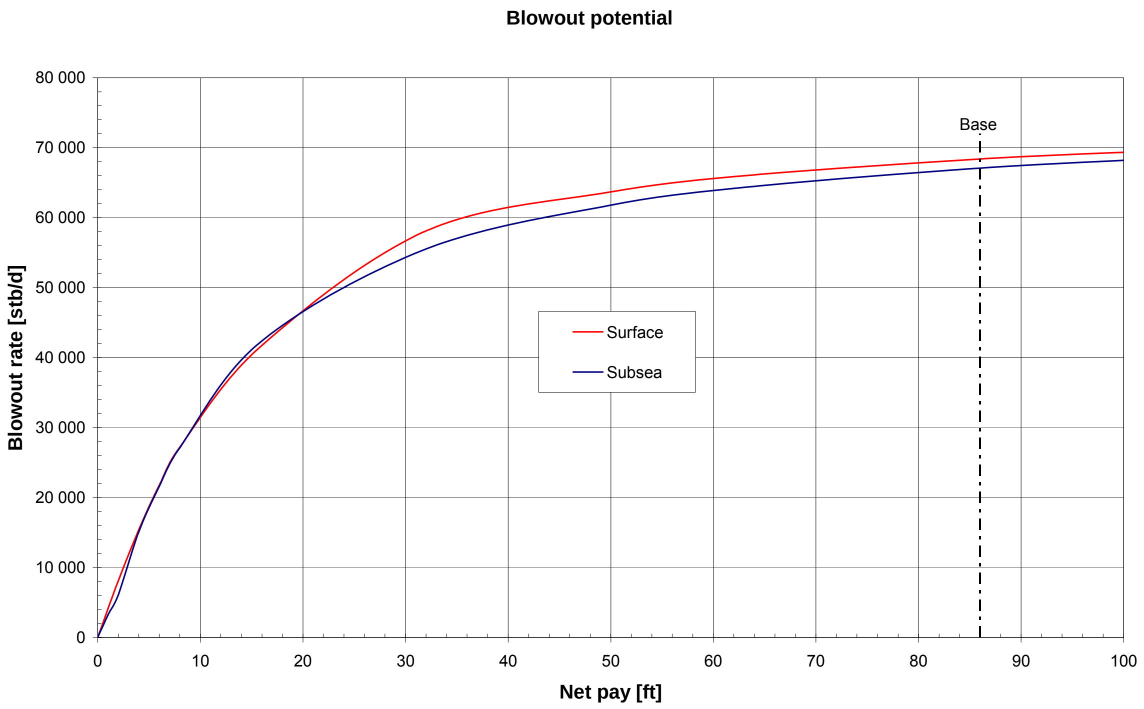


Figure 3.7: Blowout potential with flow from shoe through the drill pipe and riser

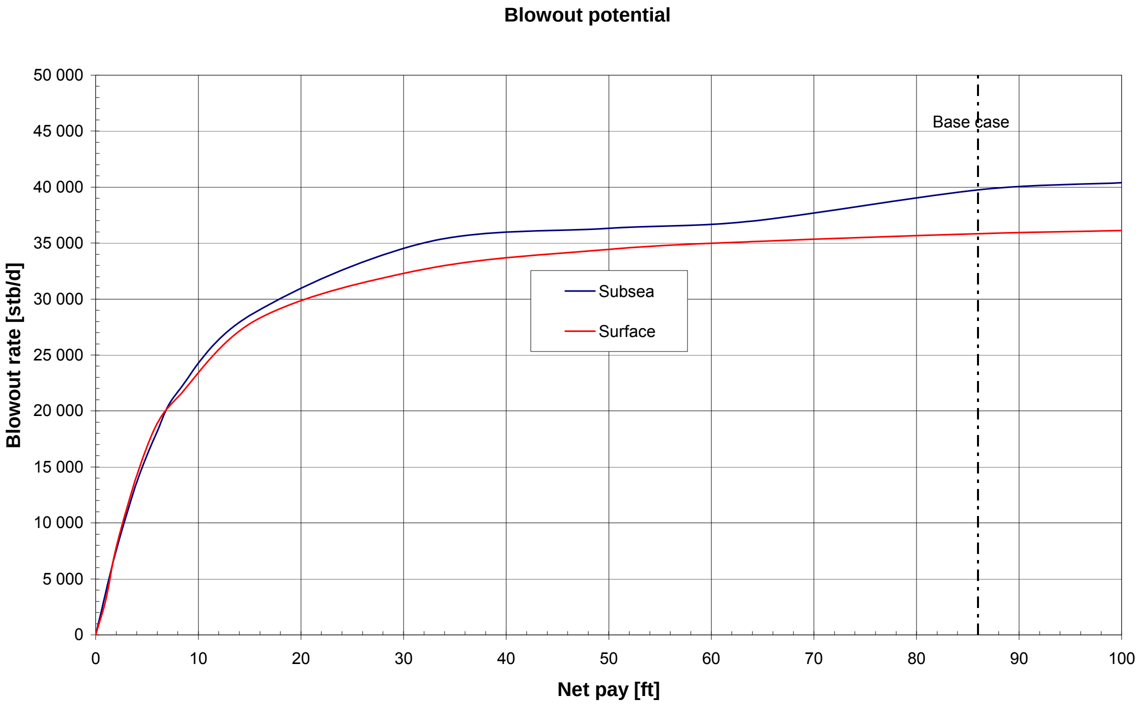


Figure 3.8: Blowout potential with flow from the shoe through drill pipe only

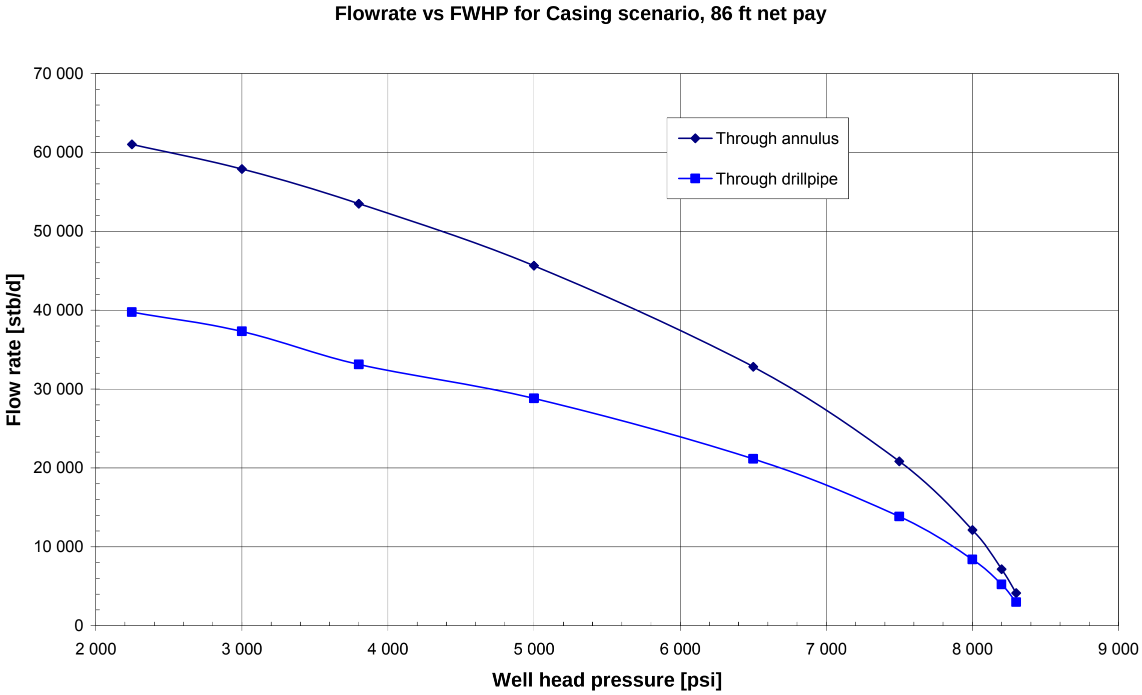


Figure 3.9: Blowout potential through the casing shoe versus FWHP

3.5 Shut-in pressures with hydrocarbons in the wellbore

If the well (full of hydrocarbons) is shut-in at surface, the estimated shut-in pressure is 6,800 psi. If the well (full of hydrocarbons) is shut-in at the seabed, the shut-in pressure is estimated to be 8,250 psi. Both pressures are above the bubble point pressure, therefore, no gas will be present when equilibrium is obtained after a long shut-in period.

Depending on the flowrate and temperature profile in the well prior to the shut-in, the simulations indicate that the peak pressures can be slightly higher than the reported settle out pressures. Examples of a subsea shut-in are shown in Figure 3.10. For a potential shut-in at surface the pressure buildups will be slower due to more gas in the wellbore.

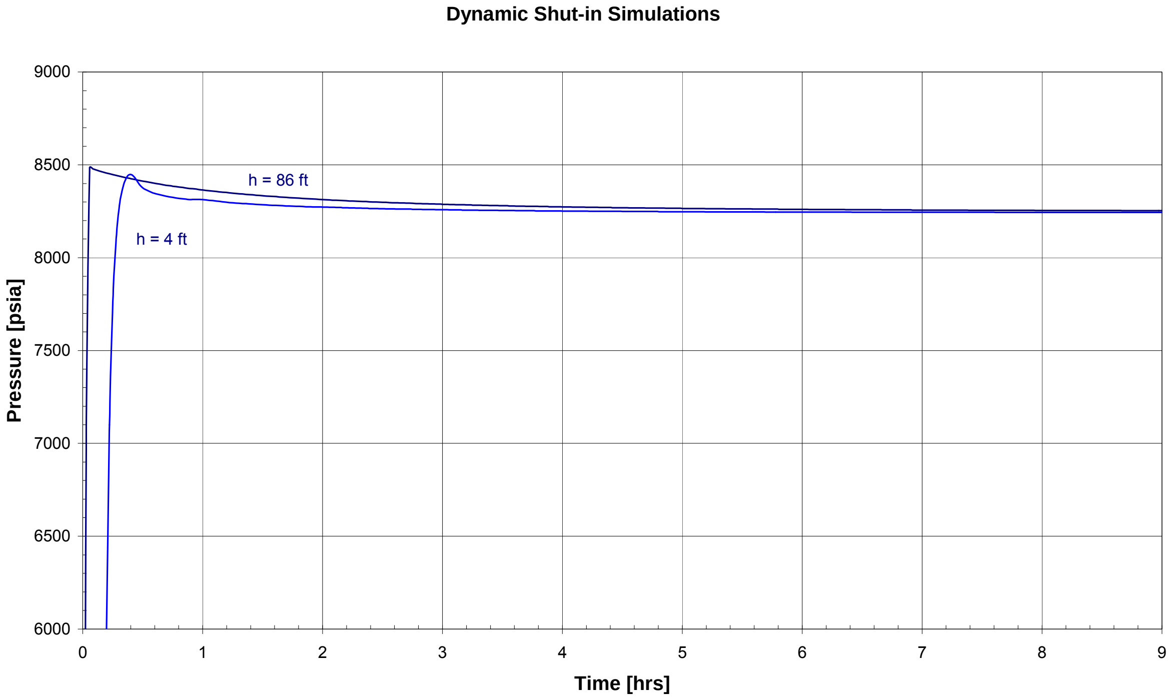


Figure 3.10: Examples of dynamic shut-in pressures, shut-in at seabed

3.6 Early Simulations

3.6.1 *Introduction*

During the negative test bleed downs, the pressure at down hole conditions dropped below the pore pressure and early in the investigation, a gain of 60 to 85 bbls was believed to have been taken. Simulations were performed assuming 12.6 ppg sand, an 85 bbl hydrocarbon influx during the negative test and 86 ft net pay. The results of these simulations are shown for:

- flow through the production casing (see Case 1 in Section 3.6.2)
- flow through the outer annulus of the production casing (see Case 2 in Section 3.6.3).

Neither of these initial simulations, which are based on the entire reservoir (86 ft net pay), being open to flow, gave a perfect match with actual events and recorded data. However, they are included in this report for completeness and they provided the foundation for the subsequent modeling that was completed.

A third case, (see Case 3 Section 3.6.5) simulates the effect of 4 ft of 13 ppg sand.

When witness accounts became available to the investigation team, it became evident that the assumed gain of 60 to 85 bbls during the negative test was primarily accounted for by a leaking BOP annular. The riser is believed to have been topped up with 50-60 bbls during this period due to the leaking BOP annular. Hence, no or only a small influx (0 - 20 bbls) was taken during the bleed downs during the negative test. This information changed the premise significantly with respect to identifying the flow path. Without the 85 bbls of initial hydrocarbon influx, close match simulations for flow through the outer annular of the production casing and up through the seal assembly can not be created even when using a net pay of 86 ft.

3.6.2 *Case 1 - Flow through casing assuming 12.6 ppg sand and 86 ft reservoir exposure.*

This case was based on early suggestions of a potential 85 bbl gain during the negative test. This case assumes 12.6 ppg reservoir pressure and 86 ft net pay (i.e. full reservoir exposure). The flow path is through the casing. Results of this simulation are shown in Figure 3.11 and Figure 3.12.

The results show a fair match of drill pipe pressure until about 21:00 hrs. However, the modeled shut-in pressures do not match the recorded data. According to the simulations, the shut-in pressure at 17:20 hrs is 200 psi lower than the recorded pressure. Further, the results indicate that the unloading of the wellbore is occurring quite fast (less than one hour). The arrival of the hydrocarbons to surface occurs too early, it is predicted that hydrocarbons will reach surface at approximately 21:15 hrs, almost 30 minutes earlier than what the witness accounts indicate. It is concluded that a lower net pay input assumption would better align with the witnessed arrival of hydrocarbons at surface. The 200 psi offset in pressure also needs to be understood.

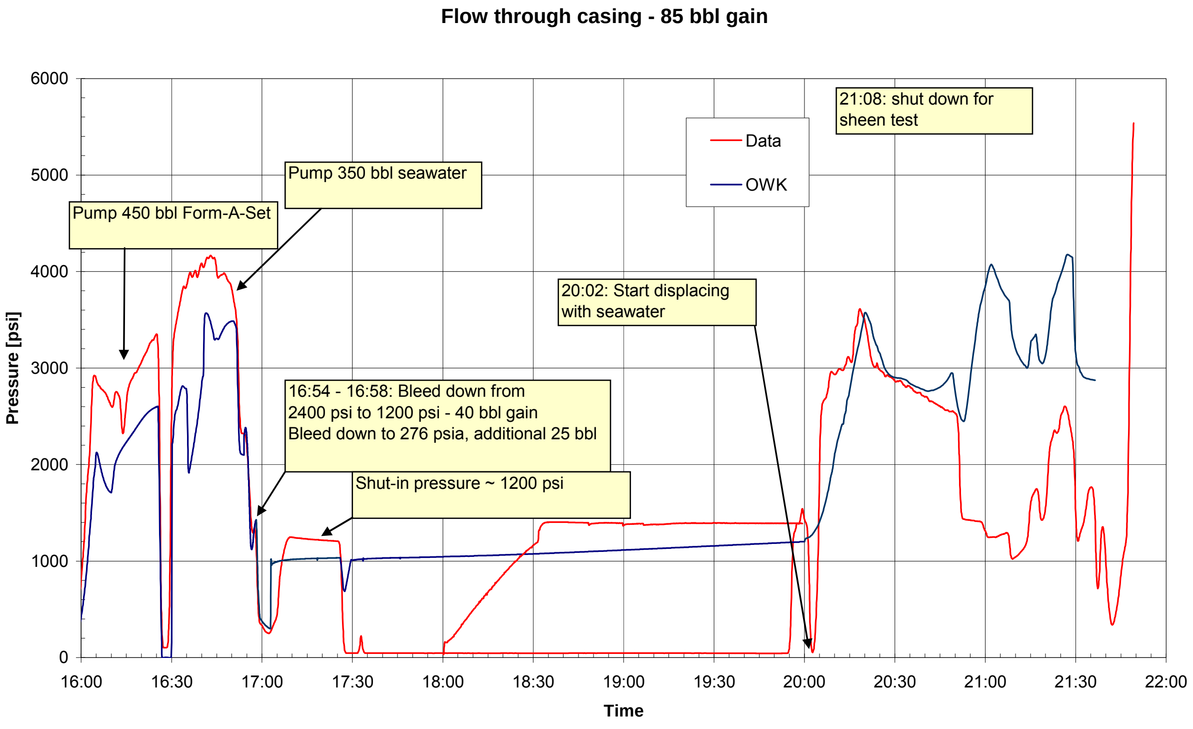


Figure 3.11:Case 1 - Flow through the casing assuming 12.6 ppg sand and 86 ft reservoir exposure. Simulated versus recorded drill pipe pressure

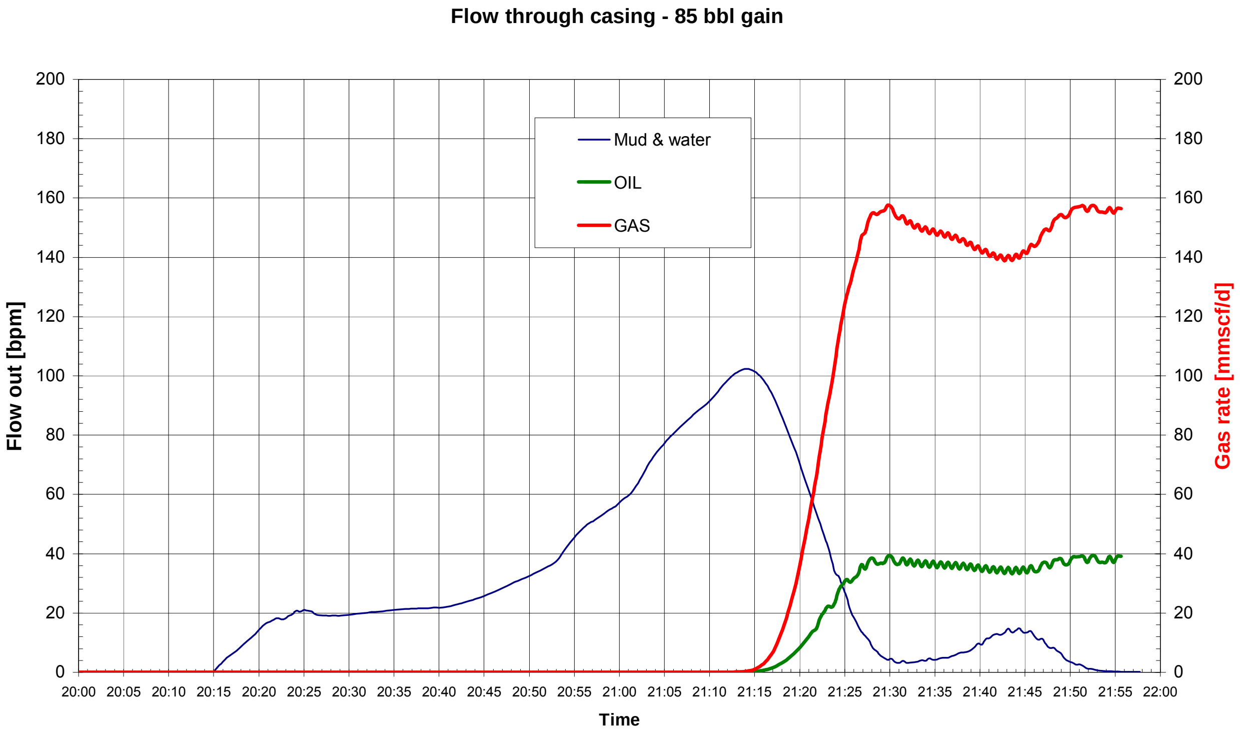


Figure 3.12:Case 1 - Flow through the casing assuming 12.6 ppg sand and 86 ft reservoir exposure. Simulated flow rates at surface

3.6.3 Case 2 - Flow through outer annulus assuming 12.6 ppg sand and full reservoir exposure.

Case 2 was based on early suggestions of a potential 85 bbl gain during the negative test. This case assumes 12.6 ppg reservoir pressure and 86 ft net pay (i.e. full reservoir exposure). The modeled flow path is through the outer annulus of the production casing. Results of this simulation are shown in Figure 3.13 and Figure 3.14.

The results of this simulation indicate that the calculated shut-in pressures are higher than the recorded. At the very end of the unloading sequence, this scenario shows a better match with the actual events compared to the casing scenario as hydrocarbons arrive at surface at about the expected time. However:

- the last two pressure buildups can only be reproduced by inclusion of a restriction in the flow path. This does not align with witness accounts of the BOP being activated after 21:41 hrs.
- during the sheen test the pressure is dropping instead of increasing as in the recorded data.

It is therefore concluded that this scenario does not adequately match the actual events or recorded data. Moreover, when the 85 bbl hydrocarbon influx is discounted, which was originally assumed to have been taken during the negative test, the scenario of flow through the casing outer annulus and the seal assembly is no longer plausible. Even on the basis that the full 86 ft of net pay is open to flow, which in itself is less likely, hydrocarbons do not arrive at surface in time to match witnessed events. It is therefore concluded that it is very unlikely that the initial flow came through the outer annulus of the production casing and through the seal assembly.

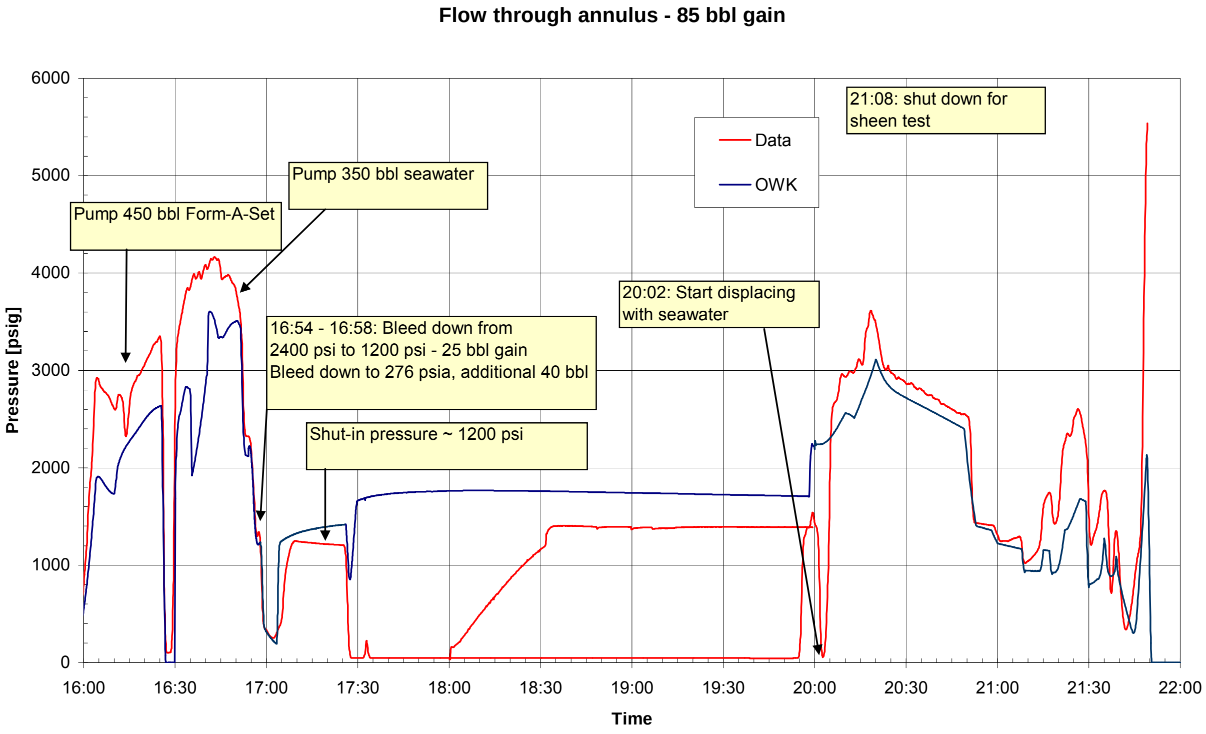


Figure 3.13: Case 2 - Flow through the outer annulus assuming 12.6 ppg sand and 86 ft reservoir exposure. Simulated versus recorded drill pipe pressure

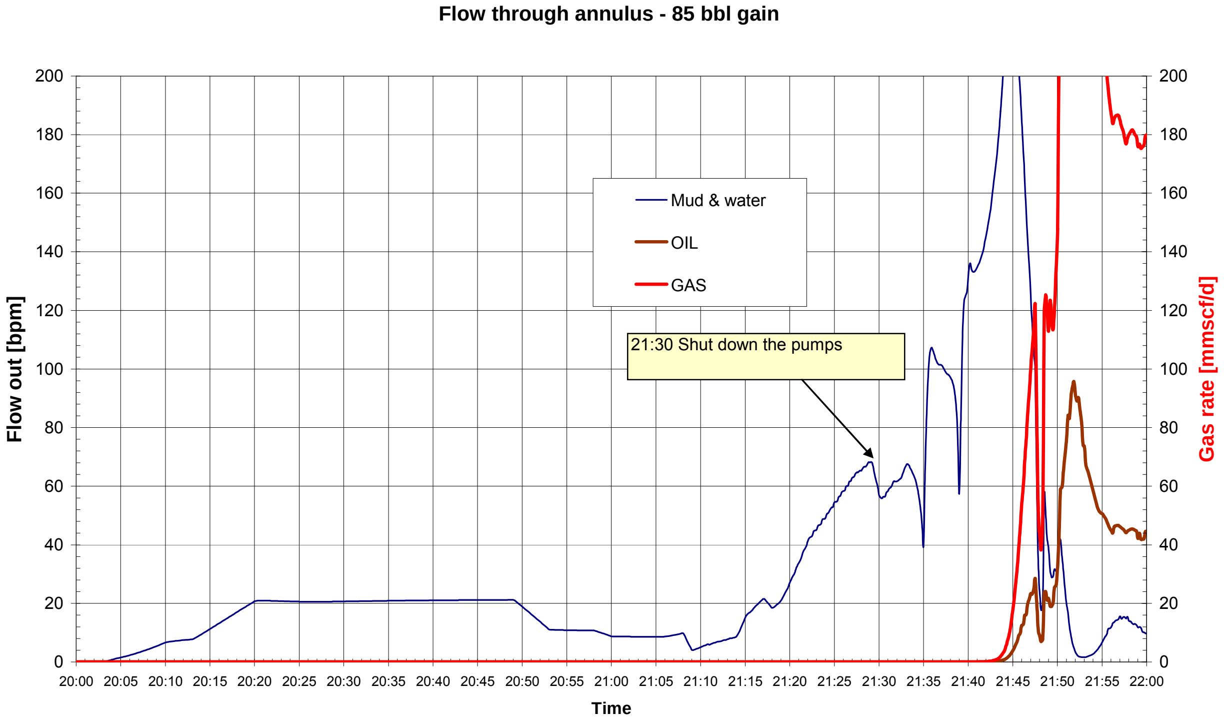


Figure 3.14: Case 2 - Flow through the outer annulus assuming 12.6 ppg sand and 86 ft reservoir exposure. Simulated flow rates at surface

3.6.4 Shut-in pressure considerations

Two shut-in periods during the negative test were used to estimate the downhole conditions and size of a potential kick by static considerations. During the period between 17:10 hrs and 17:25 hrs, the shut-in pressure was approximately 1,200 psi. During the period between 18:34 hrs and 19:57 hrs the shut-in pressure was approximately 1,400 psi.

As discussed previously, early interpretations of the bleed-downs through the drill pipe suggested an 85 bbl gain caused by an influx from the reservoir. This would force mud or water up in the drill pipe and volume calculations can determine the mud water/level in the drill pipe.

Based on the 12.6 ppg pore pressure, there is a significant difference between the kick volume required to create these shut-in pressures. It will take 190 bbl inside the casing to end up with 1,200 psi shut-in drill pipe pressure whilst it will only take 25 bbl in the outer annulus. This is observed from the initial simulation runs where the inside casing scenario ended up with a shut-in pressure of 1,000 psi based on a 85 bbl kick (see Figure 3.11).

For the outer annulus scenario, simulations showed a shut-in pressure of 1,400 psi based on an 85 bbl kick, compared to the recorded 1,200 psi (see Figure 3.13). Unknown conditions down hole also challenge these calculations as the pressure depends on several factors including the extent of any cement barrier.

The difference in shut-in pressures for the two flow path scenarios is caused by the different fluids present in the two paths. For the casing scenario, there is initially water in the drill pipe to 8,367 ft, and 14 ppg mud from this point to TD. For the outer annulus, there is 14 ppg mud from the bottom of the well up to the seal assembly at the mudline, 16 ppg spacer and water in the production casing, and water in the drill pipe (see Figure 3.15).

The investigation team subsequently concluded that during the period between 17:10 hrs and 17:25 hrs the BOP annular preventer was leaking. Therefore, the 1200 psi shut-in pressure can be discounted as the drill pipe was still in communication with the fluid in the riser. Furthermore, the 85 bbl gain can also be discounted.

If it is assumed that no influx was taken during the negative test, the resulting drill pipe shut-in pressure would be:

- 1,030 psi based on a 12.6 ppg sand if communication was through the casing shoe
- 600 psi based on a 12.6 ppg sand if communication was through the seal assembly

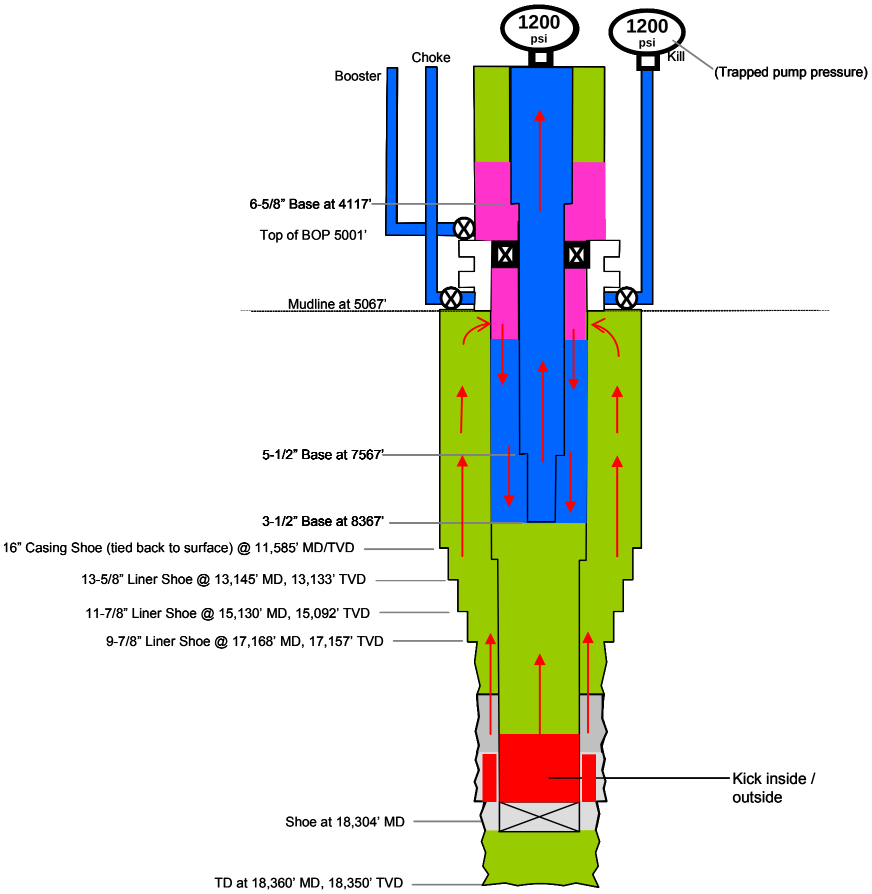

1200
psi
1200
psi
Choke
Booster
Kill
(Trapped pump pressure)
6-5/8" Base at 4117'
Top of BOP 5001'
Mudline at 5067'
5-1/2" Base at 7567'
3-1/2" Base at 8367'
16" Casing Shoe (tied back to surface) @ 11,585' MD/TVD
13-5/8" Liner Shoe @ 13,145' MD, 13,133' TVD
11-7/8" Liner Shoe @ 15,130' MD, 15,092' TVD
9-7/8" Liner Shoe @ 17,168' MD, 17,157' TVD
Kick inside /
outside
Shoe at 18,304' MD
TD at 18,360' MD, 18,350' TVD

Figure 3.15: Kick and shut-in pressures

As shown in Figure 3.16, if communication was through the casing shoe, the pore pressure would need to be 13 ppg to reach 1,400 psi. There is a 13 ppg sand in the reservoir section and therefore it is concluded that this sand probably caused the 1400 psi pressure response during the negative test by transmitting pressure through the casing shoe.

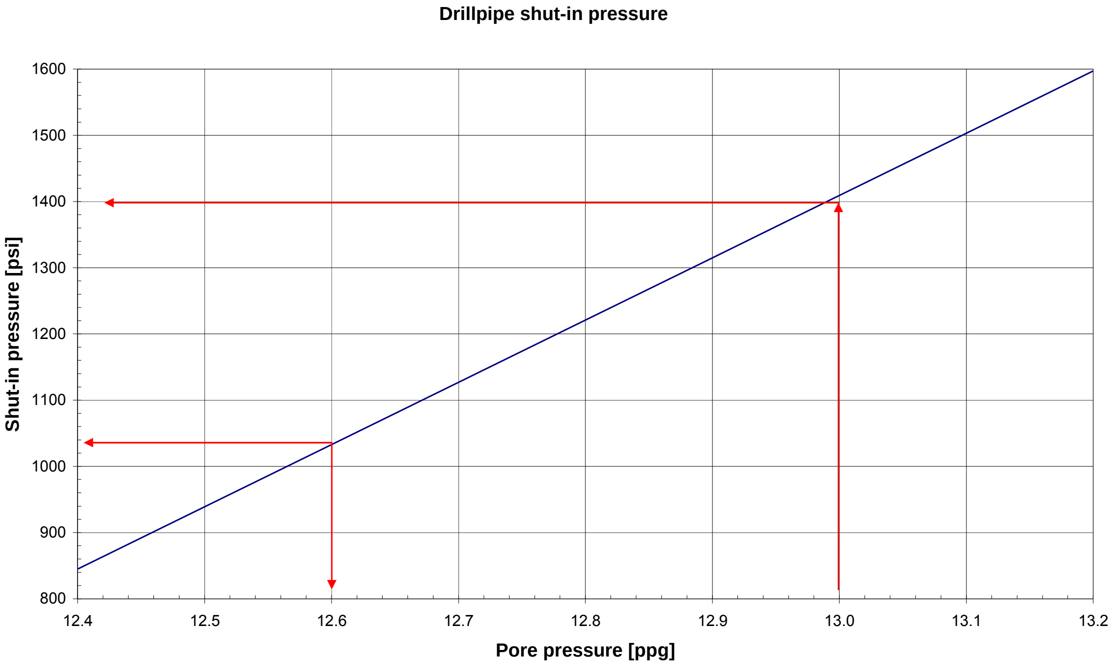


Figure 3.16: Shut-in pressures with no hydrocarbons and seawater in drill pipe

3.6.5 Case 3 - Flow through casing assuming 13 ppg sand and 4 ft reservoir exposure.

The shut-in pressure based on a 12.6 ppg pressurized sand did not match the recorded drill pipe pressure, and a new simulation was performed assuming that a 13 ppg sand was exposed to the wellbore. However, this sand has only 4 ft of net pay and the oil and gas flow rates will therefore be lower and it is expected that the hydrocarbons will arrive at surface later than what was simulated using the 86 ft of the 12.6 ppg scenario.

For this simulation, the estimated gain based on the simulations was approximately 60 bbl. The calculated shut-in pressure after the 2,400 – 250 psi bleed down was above the observed pressure of 1,200 psi, but showed a good match with the 1,400 psi shut-in pressure (see Figure 3.17). The estimated unloading sequence was in relatively good agreement with the observations (see Figure 3.18) and gas arrives at surface at about 21:45 hrs. However, the gas volumes at surface are unlikely to be adequate to cause the scale of events (explosions and fire) as portrayed in the witness accounts.

If the 13 ppg sand is able to flow it is probable that other sands will also be open to flow. As the down hole pressure reaches the point where the 12.6 ppg sands become underbalanced flow is likely to initiate from these sands, particularly in the case where the flow path is assumed to be through the production casing shoe. It is therefore concluded that, the 13 ppg sand probably caused the initial pressure increase of 1,400 psi seen during the negative test but other sands will have contributed to the flow from the well once they became underbalanced.

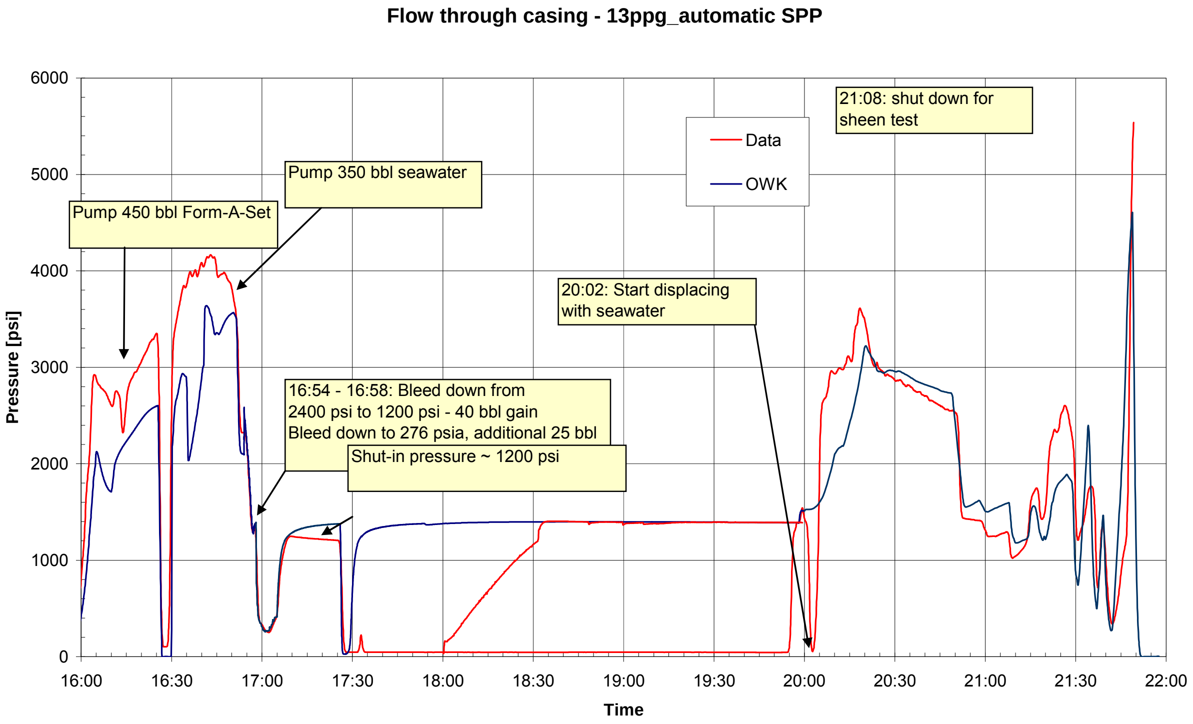


Figure 3.17: Case 3 - Flow through the casing assuming 13.0 ppg sand and 4 ft reservoir exposure. Simulated versus recorded drill pipe pressure.

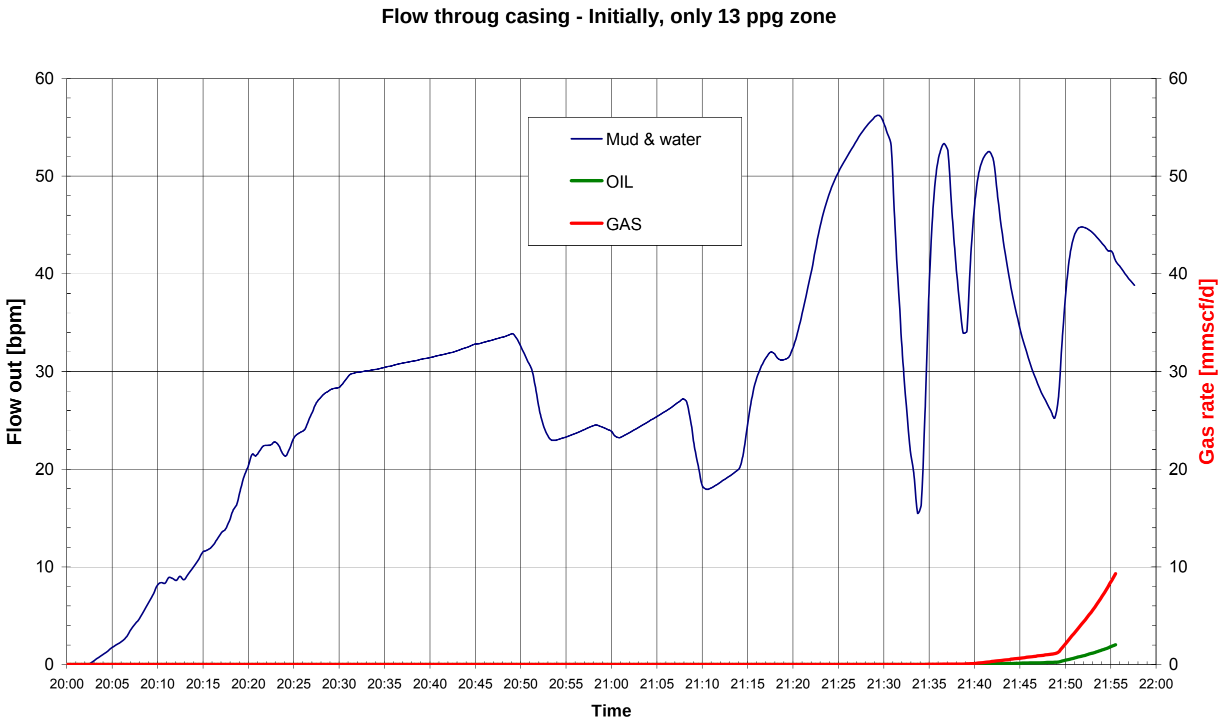


Figure 3.18: Case 3 - Flow through the casing assuming 13.0 ppg sand and 4 ft reservoir exposure. Simulated flow rates at surface.

3.6.6 Discussion on Cases 1-3

The constant shut-in pressure of 1,400 psi measured on the drill pipe between 18:35 hrs and 20:00 hrs cannot be explained based on a pore pressure of 12.6 ppg and the conclusion from the investigation team of a much smaller influx (0 - 20 bbls) during the negative test. Assuming zero hydrocarbon influx, mud in the wellbore and seawater in the drill pipe, the shut-in pressure should be 1,030 psi if communication to the reservoir was through the casing shoe, and only 600 psi if communication was through the seal assembly. However, a sand pressurized at 13.0 ppg matches the observed 1,400 psi shut-in if the reservoir pressure is communicated through the shoe. If the pressure is communicated from a 13.0 ppg sand through the outer annulus, the resulting shut-in pressure is still too low.

3.7 Final Simulations

3.7.1 Introduction

Witness accounts indicate that the riser was topped up with approximately 50 bbls of mud between 17:12 hrs and 17:22 hrs and therefore most of the bleed volumes witnessed during the negative test were most likely caused by a leak in the annular preventer. This information combined with insights gained in our first series of simulations guided us to focus our Final Simulations assuming the following:

- no influx during the negative test
- net pay between 13 ft and 16.5 ft of 12.6 ppg sand.

Case 4 includes a final simulation for flow through the production casing outer annulus and comes to the conclusion that flow through the shoe is the most credible scenario. Cases 5, 6 and 7 are all based on flow through the production casing and Case 7 is the final simulation run, the investigation team uses Case 7 to support several elements of their analysis in the investigation report.

3.7.2 Case 4 - No influx prior to 20:02 hrs, 15 ft net pay of 12.6 ppg sand and flow through outer annulus and casing shoe.

Case 4 assumes 12.6 ppg reservoir pressure and 15 ft net pay. Further, it is assumed that the well was fully filled with water, spacer and mud and that no influx was taken before the circulation at 20:02 hrs .

When circulation starts, the pump pressure and the bottom hole pressure increase. At 21:08 hrs, the pumps are stopped for a sheen test, and the drill pipe pressure is 1,000 psi, but increasing. At this point in time, 1,300 bbl of water has been pumped, and both the drill pipe and the volume between the drill pipe and 9 ⅞" casing up to the seabed is filled with water. The pump rate has ranged between 500 and 1,250 gpm (see Figure 3.20) and this is sufficient to obtain effective transportation and displacement of the fluids up through the production casing (between the drill pipe and 9 ⅞" casing). The production casing is therefore fully displaced to seawater above the bottom of the drill pipe and into the riser at 21:08 hrs.

At 21:08 hrs, the calculated average fluid density at the formation via the outer annulus of the production casing is equivalent to 13.6 ppg. The reservoir would be overbalanced and no influx can be taken. This is because the annulus of the production casing is full of 14 ppg mud all the way up to the seal assembly.

Figure 3.19 shows a linear static pressure profile in the well with 1,000 psi drill pipe pressure, seawater in the drill pipe, seawater in the production casing above the bottom of the drill pipe and 14 ppg mud in the production casing outer annulus below the seal assembly. In order to balance a 13 ppg sand at 17,800 ft based on this condition, the top of the hydrocarbon influx should be at 16,700 ft (see Figure 3.19). This requires a 25 bbl influx assuming that the top of the cement is at 17,450 ft, with only smaller channels below to the 13 ppg sand.

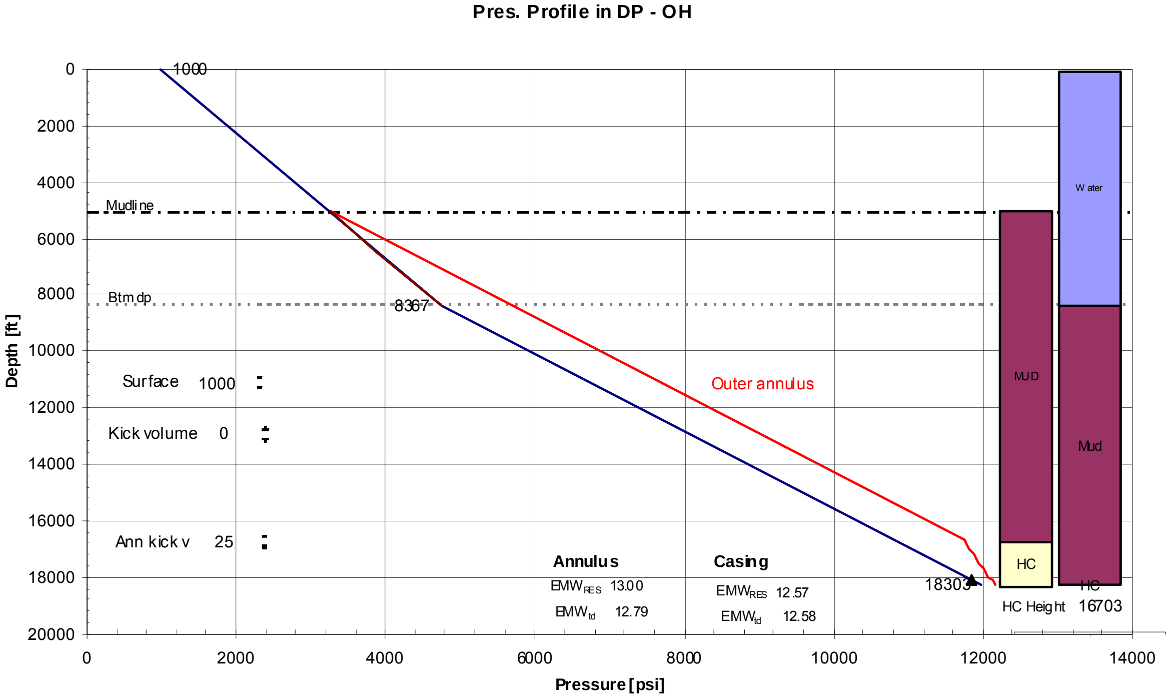


Figure 3.19:Pressure profile in outer annulus to balance 13 ppg sand

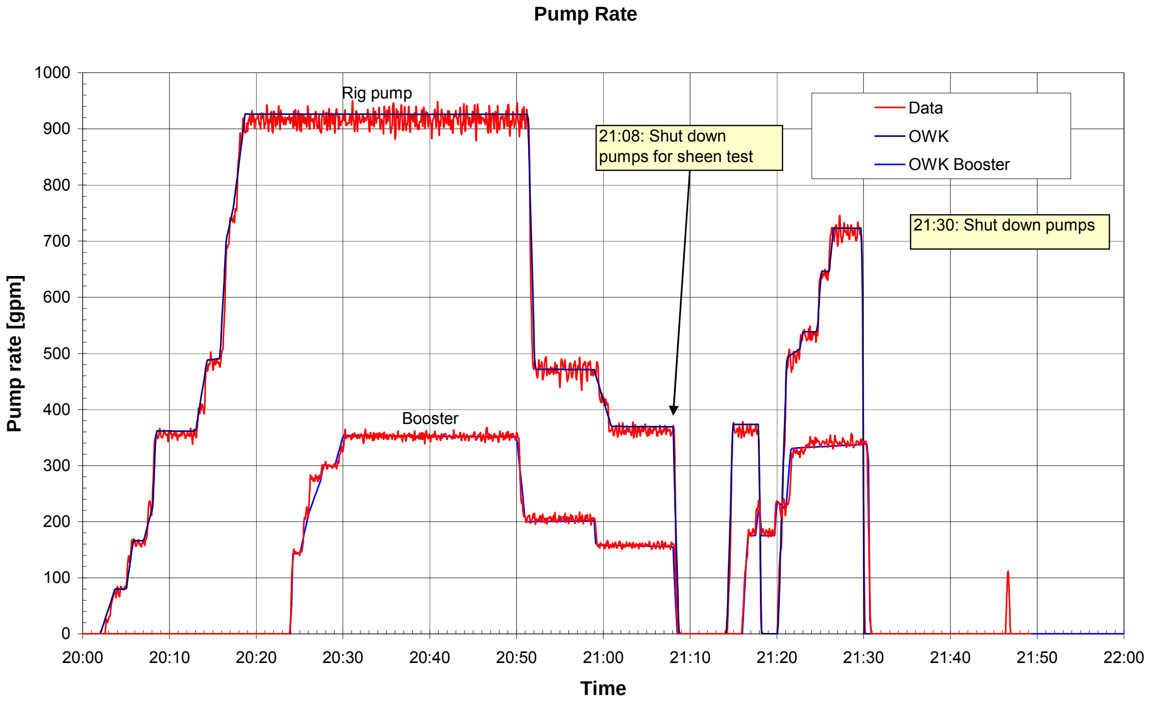
At 21:08 hrs, the calculated average fluid density at the formation via the production casing is less than 12.6 ppg and therefore the flow path through the production casing is in an underbalanced condition. The investigation team calculated that a 39 bbl gain was taken between 20:52 hrs and 21:08 hrs, it is concluded that the influx is coming via the production casing shoe.

The simulation through the casing shoe shows a fairly good match with the recorded drill pipe pressure during the circulation job until the pumps are shut down at 21:30 hrs (see Figure 3.21). However, pressure gradients appear to be steeper, for example during the sheen test period from 21:08 hrs to 21:14 hrs (see Figure 3.21); this is indicative of a higher predicted flow rate than what actually occurred. At 21:30 hrs the simulations predict a decreasing drill pipe pressure in contrast to the recorded pressure data showing several pressure peaks. This decrease in pressure is primarily caused by the lighter hydrocarbon fluid rising through the production casing past the end of the drill pipe and displacing the denser seawater.

Figure 3.21 shows the recorded drill pipe pressure versus the modeled drill pipe pressure for this case (flow through the shoe with an assumption of 15 ft net pay and 12.6 ppg pore pressure). Figure 3.22 shows plots of the surface flow rates and reservoir influx for the same case.

With the exception of the pressure response after 21:30 hrs, this case presents a close match to recorded pressure data. The simulation also provides a good predictive match with the observed timing of the actual arrival of hydrocarbons at surface. It is possible to create a pressure response match after 21:30 hrs by simulating BOP elements closing but not fully sealing; this analysis is detailed under Case 6 in Section 3.7.7. However, witness accounts suggest that BOP activation only occurred after 21:40 hrs, therefore the pressure increase from 21:31 hrs to 21:34 hrs cannot be explained by closing in the well at the BOP.

Combining all of the insights from the simulations presented so far in the report demonstrates that flow through the outer annulus of the production casing is not a credible scenario. The remaining simulations in this report consider flow through the production casing. These final simulations focus on adjusting the net pay input assumption and closure of BOP elements after 21:41 hrs.



21:08: Shut down pumps for sheen test

21:30: Shut down pumps

Figure 3.20: Pump schedule during the period between 20:00 hrs – 21:30 hrs. Recorded data versus input to model

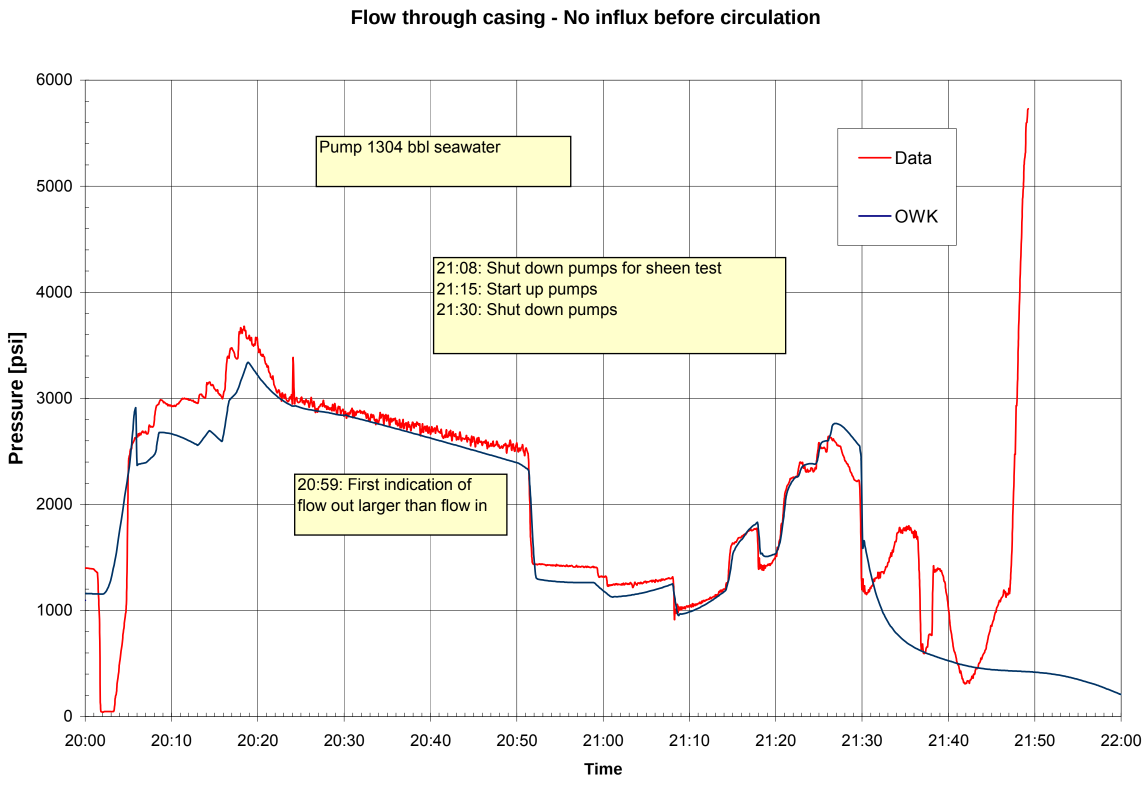


Figure 3.21:Case 4 - Flow through casing assuming 12.6 ppg sand and 15 ft reservoir exposure. Simulated versus recorded drill pipe pressure.

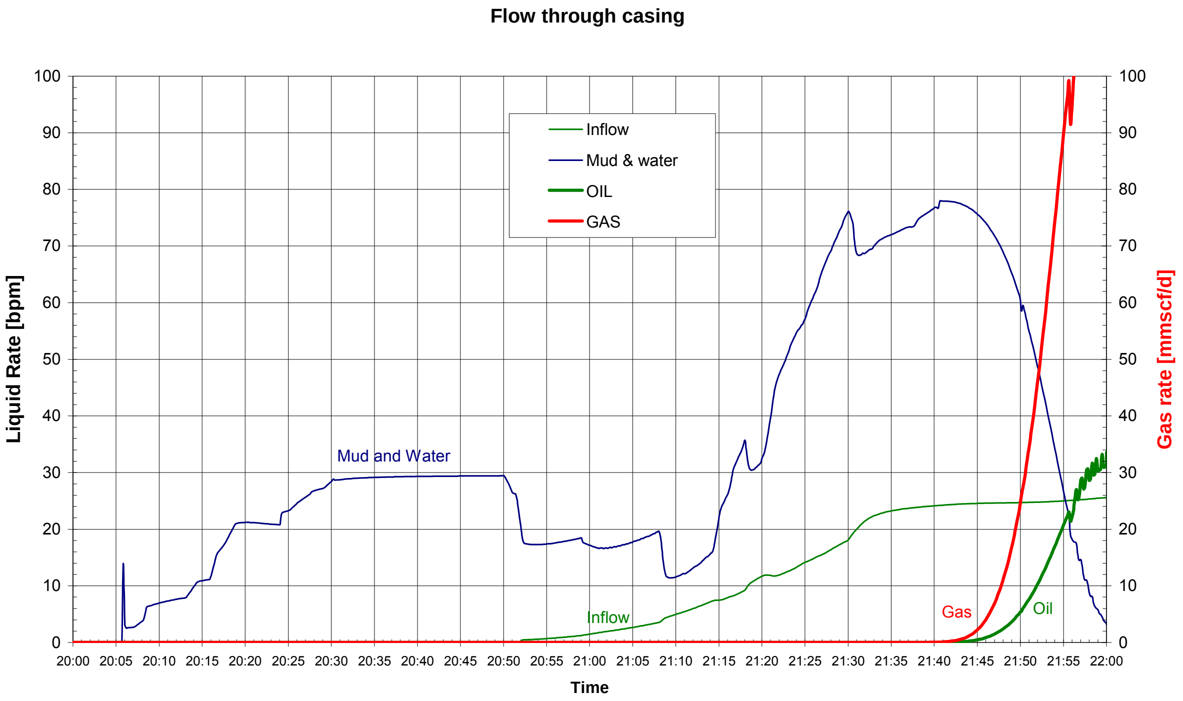


Figure 3.22:Case 4 - Flow through casing assuming 12.6 ppg sand and 15 ft reservoir exposure. Simulated flow rates at surface.

3.7.3 Pressure drop in surface lines

In order to investigate the potential surface pressure increases during the well blow-out several simulations were performed for 14 ppg mud flowing through 500 ft of horizontal line. The 500 ft line length does not reflect actual lengths of pipe on the rig but is a nominal length used in the model. These simulations were completed to gain an appreciation of the range of possible pressures for different liquid flow rates and possible surface flow paths.

The pressure drop down the 18 in line (same diameter as the main riser flow line to the mud pits) is low even with flow rates up to 300 bbl/min; this demonstrates its capacity to transport large volumes of liquid. The 14 in lines (same diameter as the main starboard and port diverter lines) can also accommodate high rates of liquid flow (see Figure 3.23).

It should be noted that these simulations do not reflect the impact of high gas and liquid flow rates occurring simultaneously at surface. Higher pressure increases would occur in this event.

The vent line from the mud gas separator is 245 ft high, which would create a hydrostatic head of 180 psi based on the 14 ppg mud. A burst disk is installed to protect the gas separator, and is supposed to pop open at 15 psi. The flow would then be routed through a 6" line overboard with the vent line still open. Also, the separator itself was not rated for high pressures.

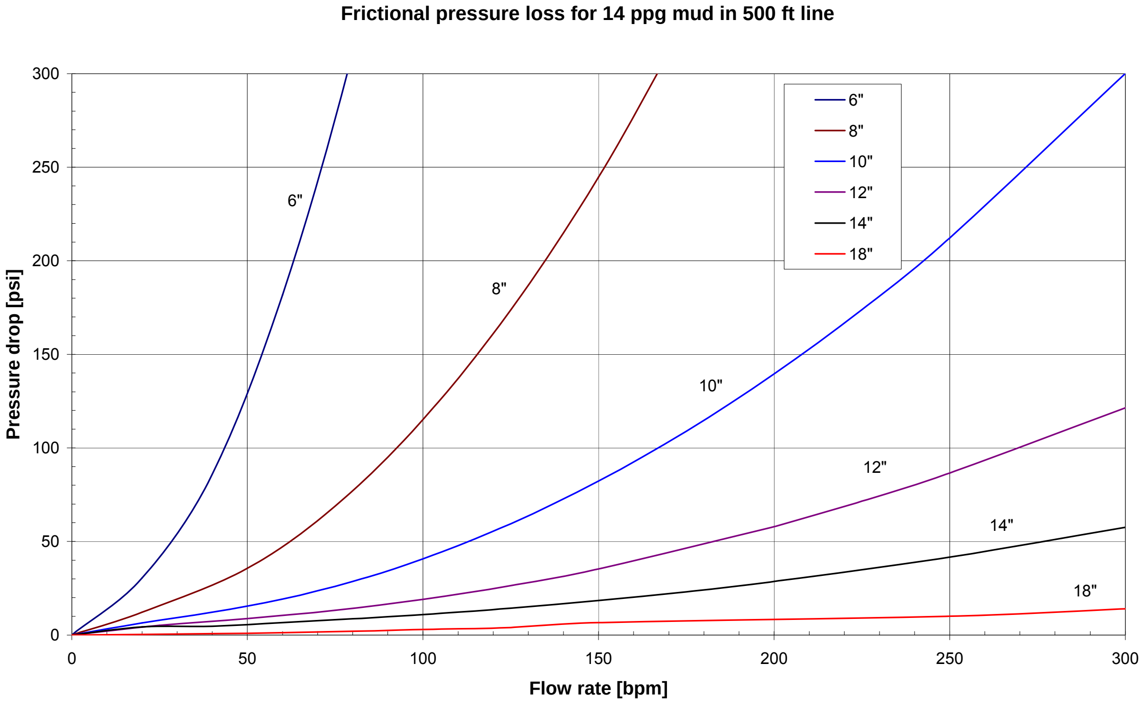


Figure 3.23: Frictional pressure loss in 500 ft pipe with 14 ppg mud

3.7.4 Pressure drop across a leaking annular BOP

Simulations were performed to investigate the pressure drop that would occur in a situation with mud flow through a leaking annular BOP between the riser and the 5 ½" drill pipe (see schematic of an annular BOP at Figure 3.24). The total flow area of a fully open annular is 252 in², and Figure 3.25 shows the pressure drop versus opening for two fixed flow rates of 14 ppg mud. As can be seen from Figure 3.25, only minor pressure drops occur before the annular reaches a 97 % closed position.

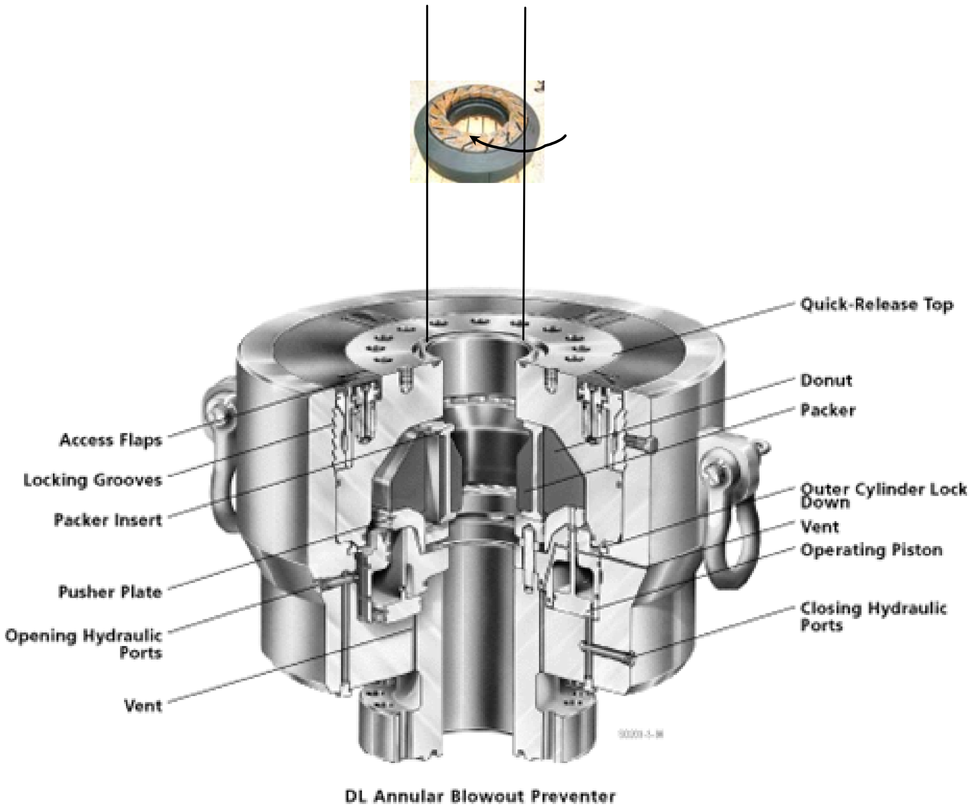

Quick-Release Top
Donut
Packer
Access Flaps
Locking Grooves
Packer Insert
Outer Cylinder Lock Down
Vent
Operating Piston
Pusher Plate
Closing Hydraulic Ports
Opening Hydraulic Ports
Vent
DL Annular Blowout Preventer

Figure 3.24: Annular blowout preventer

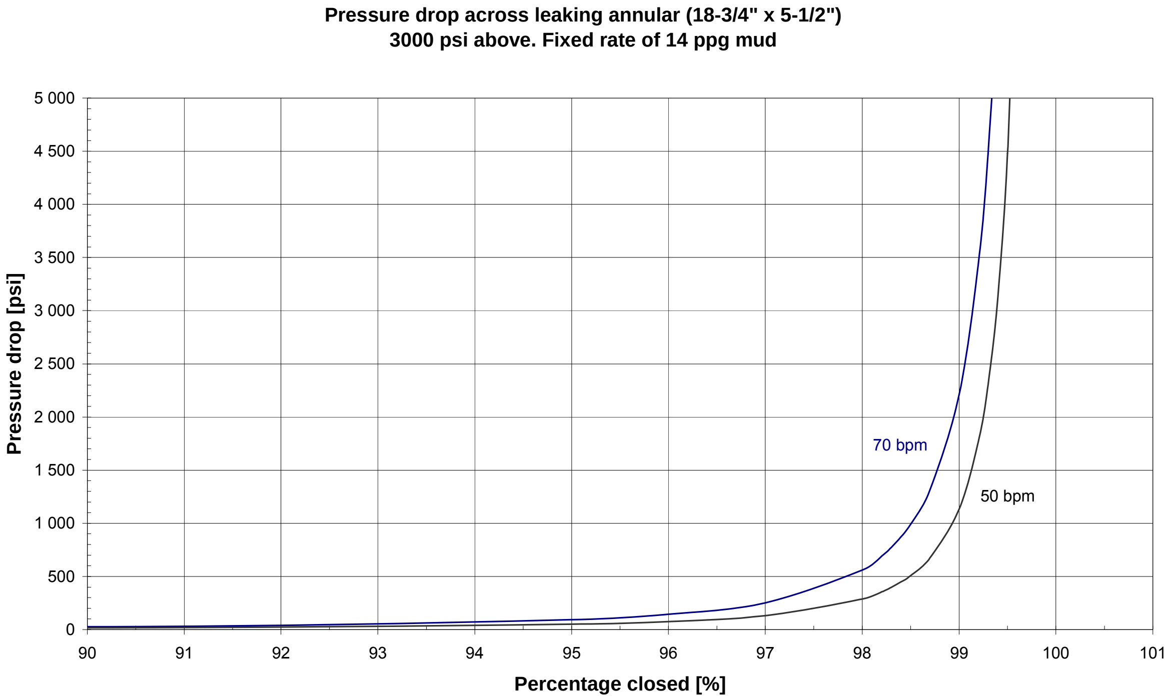


Figure 3.25: Pressure drop across BOP for various rates of BOP closure

3.7.5 Sensitivities with respect to potential events after 21:30

The actual pressure readings show fluctuations in pressure between 21:30 hrs and 21:50 hrs (see Figure 3.26). These fluctuations cannot be solely explained by the transient effects occurring in the wellbore at this time, such as variation in inflow performance, changes in wellbore fluids, gas flashing, variation in flow regime, swapping of phases etc. It is therefore believed that, down-hole restrictions in the flow path (partly sealing annular preventers), additional back pressure caused by surface piping and equipment and/or bleed back of fluids contributed to the generation of some of the observed pressure response.

Included in the simulation cases 5,6 and 7 are scenarios which explain the possible causes of these pressure fluctuations.

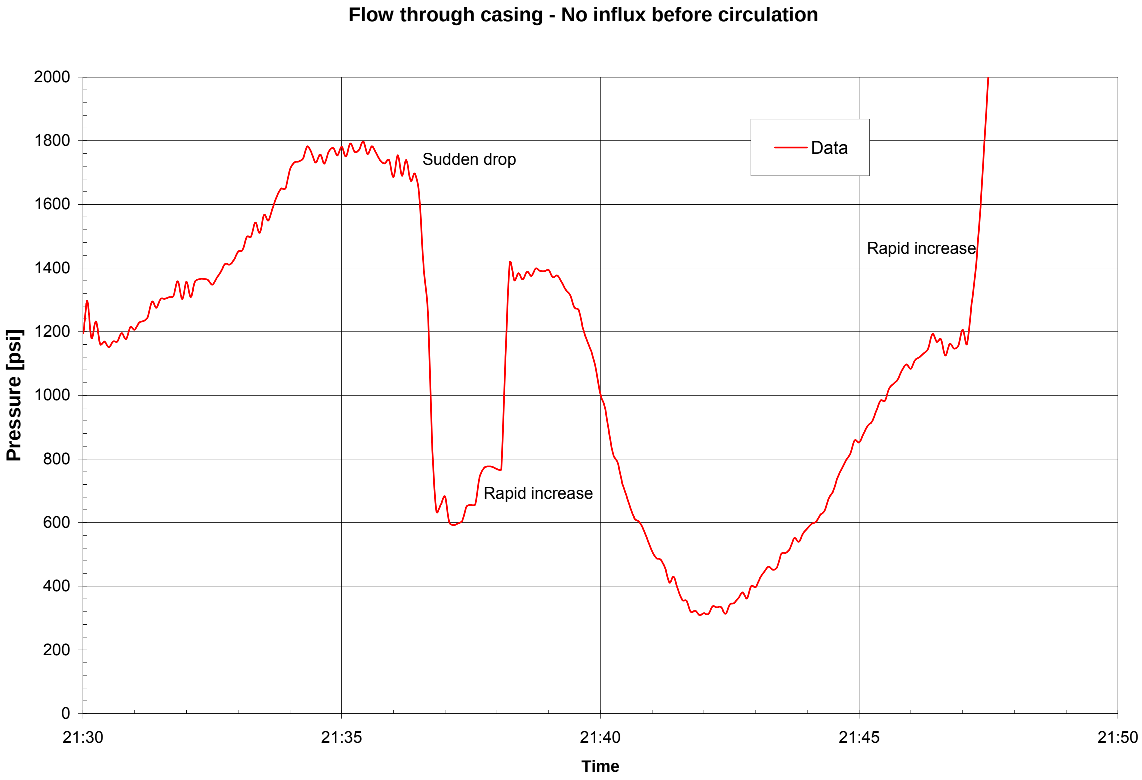


Figure 3.26: Pressure fluctuations the last minutes before explosion

3.7.6 Case 5 - Well shut-in at surface at 21:30

As in Case 4, Case 5 assumes 12.6 ppg reservoir pressure and 15 ft net pay. Further, it is assumed that the well was fully filled with water, spacer and mud and that no influx was taken before the circulation at 20:02 hrs. The flow path is through the casing shoe. This case assumes that the well is shut-in at surface at 21:30 hrs by closing the riser diverter and having no open flow path. The modeled pressure response indicates a quicker pressure buildup than shown by the recorded data (see Figure 3.27).

It is believed that an absolute maximum back pressure of 200 psi can be generated by flowing mud and water through the mud gas separator (MGS) and other surface equipment. At these surface pressures, equipment will begin to fail including the MGS vessel and the riser slip joint seals if selected in the lower pressure mode (100 psi). It is concluded that a small proportion of the pressure increase between 21:31 hrs and 21:34 hrs could be generated by back pressure at surface through the riser but it cannot explain the majority of the 610 psi increase.

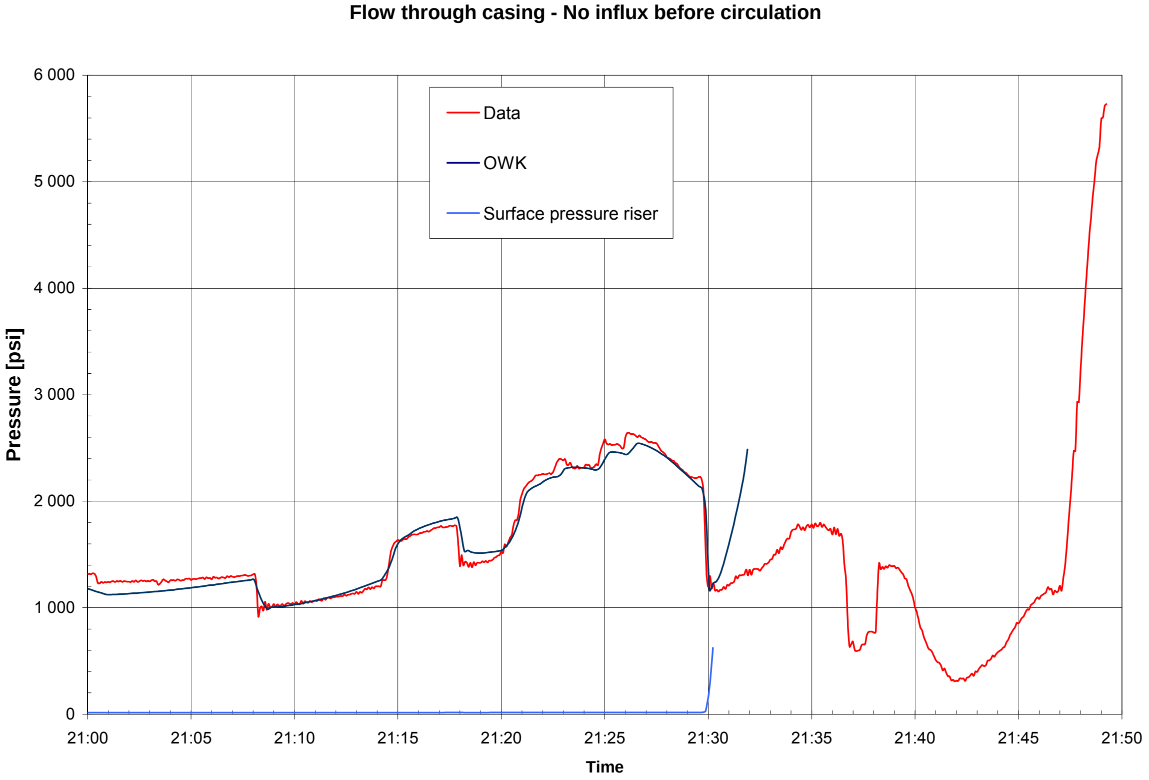


Figure 3.27:Case 5 - Pressure response for a sudden shut-in at surface (no flow)

3.7.7 Case 6 - BOP closing at 21:30 but not sealing until 21:47

As in Cases 4 and 5, Case 6 assumes 12.6 ppg reservoir pressure and 15 ft net pay. This simulation assumes that the annular of the BOP was closed but leaking from 21:31 hrs.

A fully closed and sealing BOP annular at 21:31 hrs would cause a much higher pressure increase than the recorded data shows. The simulation uses a controller to control the position of the BOP annular to allow a match with the recorded drill pipe pressure (see Figure 3.28). The annular BOP open/close sequence required to reproduce this pressure match is inconsistent with the expected crew actions or annular BOP response. However, this simulation provides some useful insights and was completed to help determine what mechanisms might have generated the recorded pressure response in the last 30 minutes.

In addition to BOP closing, scenario Case 6 also investigates potential causes of the sudden pressure drop and buildup between 21:36 hrs and 21:38 hrs. Two scenarios were tested:

- the instantaneous opening of a BOP annular.
- the bleed off of fluid from the drill pipe at surface.

The simulations suggest that the rapid pressure drop and build-up can only be generated by bleeding through the drill pipe at surface. When trying to simulate this effect mechanically at the BOP, by instantaneous opening and closing of a BOP element, the pressure transient effect created a much slower pressure response than that actually recorded (see Figure 3.29). However, as shown in Figure 3.30, the rapid pressure response could be simulated by bleeding off the drill pipe pressure at surface.

The evidence from witness accounts suggests that activation of the BOP did not occur before approximately 21:40 hrs, this is just before the second pressure increase. Hence, the first pressure increase must have been caused by mechanisms other than a partly sealing BOP annular preventer. Case 7 investigates the mechanisms that may have created the first pressure increase from 21:31 hrs to 21:34 hrs.

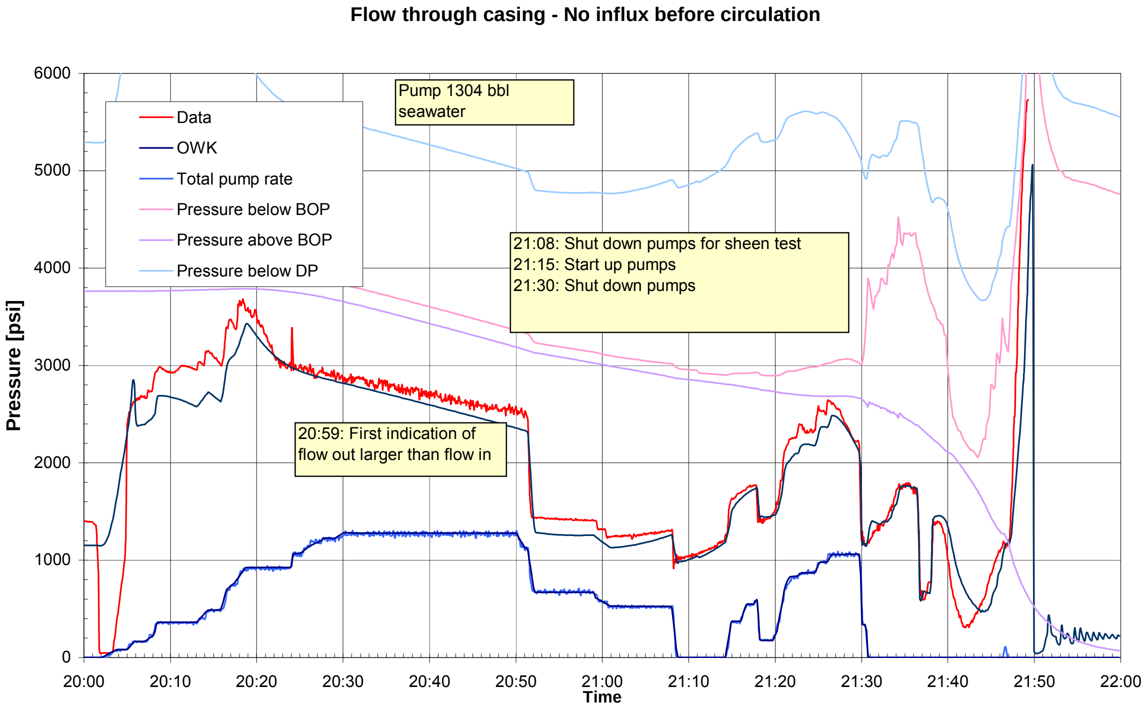


Figure 3.28: Case 6 - Simulations of circulation with flow through shoe, pressure buildups (pressure match by means of a controller).

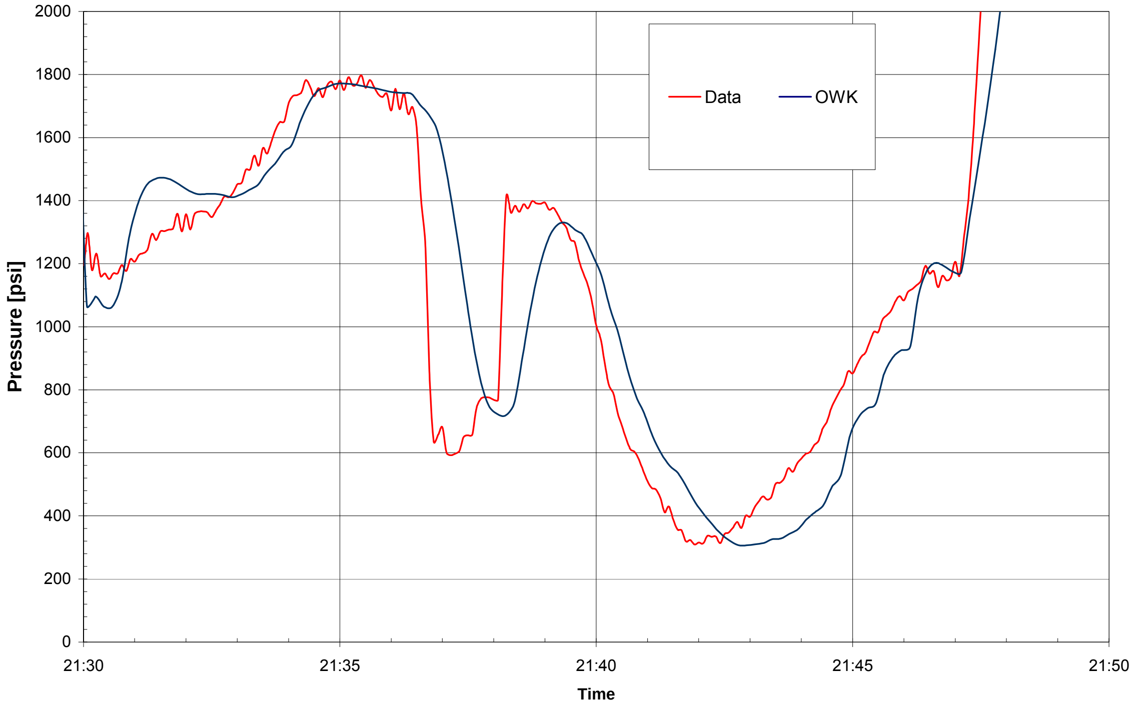


Figure 3.29: Case 6 - Simulated pressure response for an instantaneous opening of blowout preventer annular.

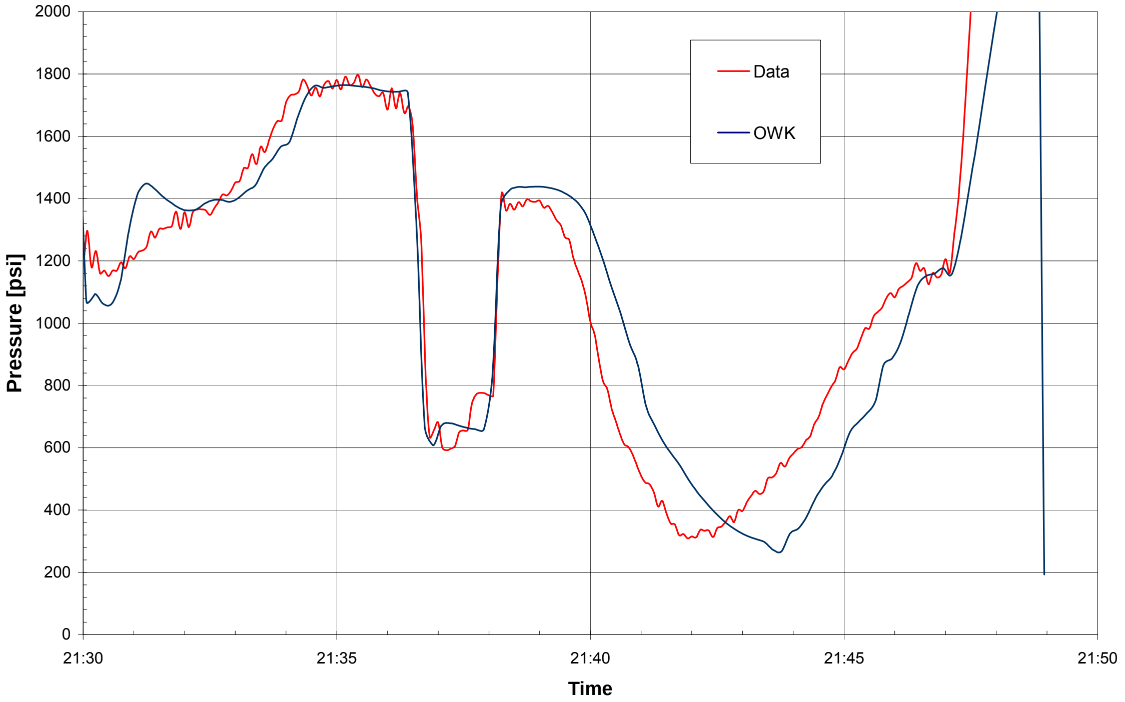


Figure 3.30: Case 6 - Simulated pressure response for a bleed back through drill pipe at surface.

3.7.8 Case 7 - BOP closed at 21:41 but not sealing until 21:47

Case 7 assumes a lower volume of hydrocarbon influx was taken prior to 21:30 hrs; this was achieved by using 13 ft of net pay of 12.6 ppg sand. When the pumps are shut down at 21:30 hrs the pressure drops creating a higher drawdown on the reservoir and from this point forward 16.5 ft of net pay is assumed in the simulation.

By slowing down the hydrocarbon influx rate there is still 14 ppg mud below the bottom of the drill pipe in the production casing at 21:30 hrs. When the mud pumps are shutdown at 21:30 hrs, the mud flows past the tail of the drill pipe replacing the lighter seawater/mud mix with 14 ppg mud. This results in an increasing drill pipe pressure due to the increasing average density above the tail of the drill pipe (see Figure 3.32).

The second increase at 21:42 hrs cannot be explained by a similar effect; by 21:42 hrs all of the mud is above the tail of the drill pipe and it is being replaced by lighter hydrocarbons. This would cause a further pressure drop and not the increase in pressure recorded (see Figure 3.31). We have only been able to explain the increase in pressure at 21:42 hrs by a closed but leaking BOP annular (see Figure 3.32). As a point of confirmation, Figure 3.32 also shows the drill pipe pressure response if the BOP annular fully sealed; a much higher pressure increase is shown than what was recorded. The assumption of a leaking BOP annular is also supported by erosion seen on the recovered drill pipe.

At 21:47 hrs it is assumed that a BOP element fully seals the well. The modeled shut-in pressure closely matches the recorded pressure (see Figure 3.32).

Figure 3.33 shows the cumulative influx of hydrocarbons and the influx rate in stb/m for Case 7.

Figure 3.34 shows the surface flow rates for Case 7. Gas arrives at surface at about 21:46 hrs and rapidly increases in rate to above 160 mmscfd, the arrival time supports the possibility of gas alarms going off about this time and the explosion occurring at about 21:49 hrs.

Figure 3.35 shows the pressures above and below the BOP for Case 7.

The nature of the transient pressure signature during the last minutes before the BOP finally seals at 21:47 hrs is challenging to determine due to several factors. The exact location of the fluid fronts will affect the observed pressure fluctuations and these will again be affected by the reservoir inflow. In the simulations, a fixed net pay has been used, but in reality, this property can change with changing down hole conditions. It is possible that initially, only smaller channels in the cement were open between reservoir and the wellbore. Later, as the drawdown increases, more of the reservoir could be exposed and hence increase the productivity.

Case 7 is the final simulation run completed in this report; this is the case that most closely matches the actual witnessed events and recorded data leading up to and during the accident. The investigation team uses the modeled outcomes from Case 7 to support several elements of their analysis in their final report.

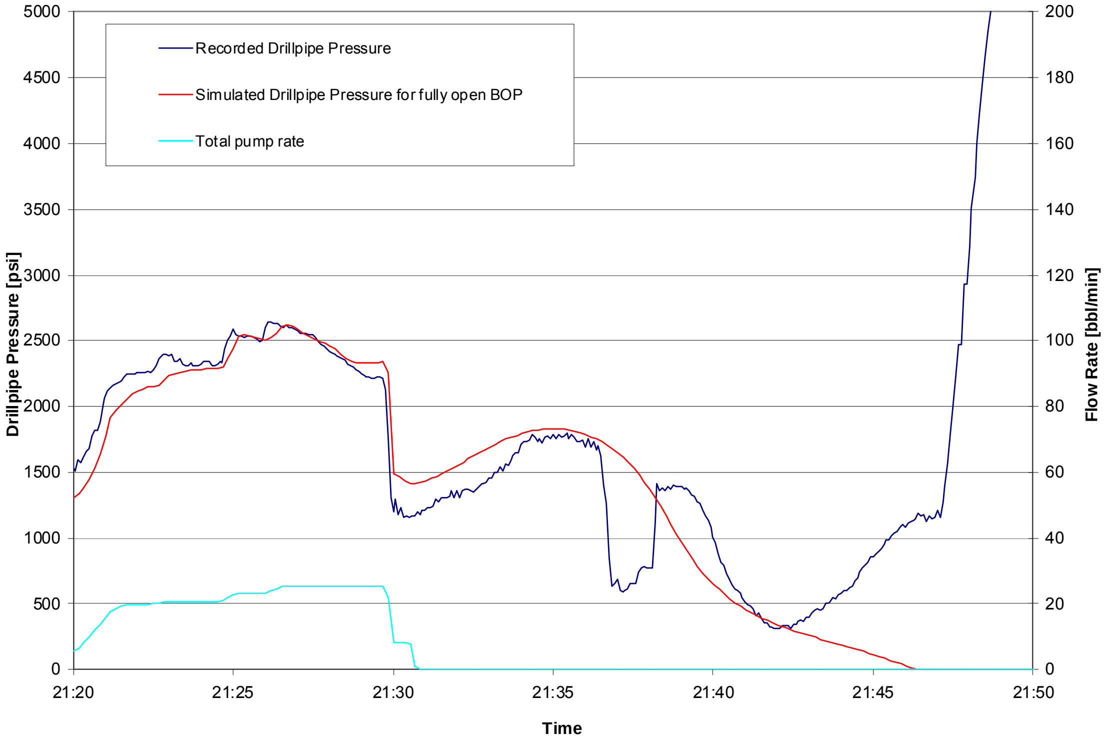


Figure 3.31: Case 7 - Pressure response for simulations without closing BOP (not accounting for the surface bleed)

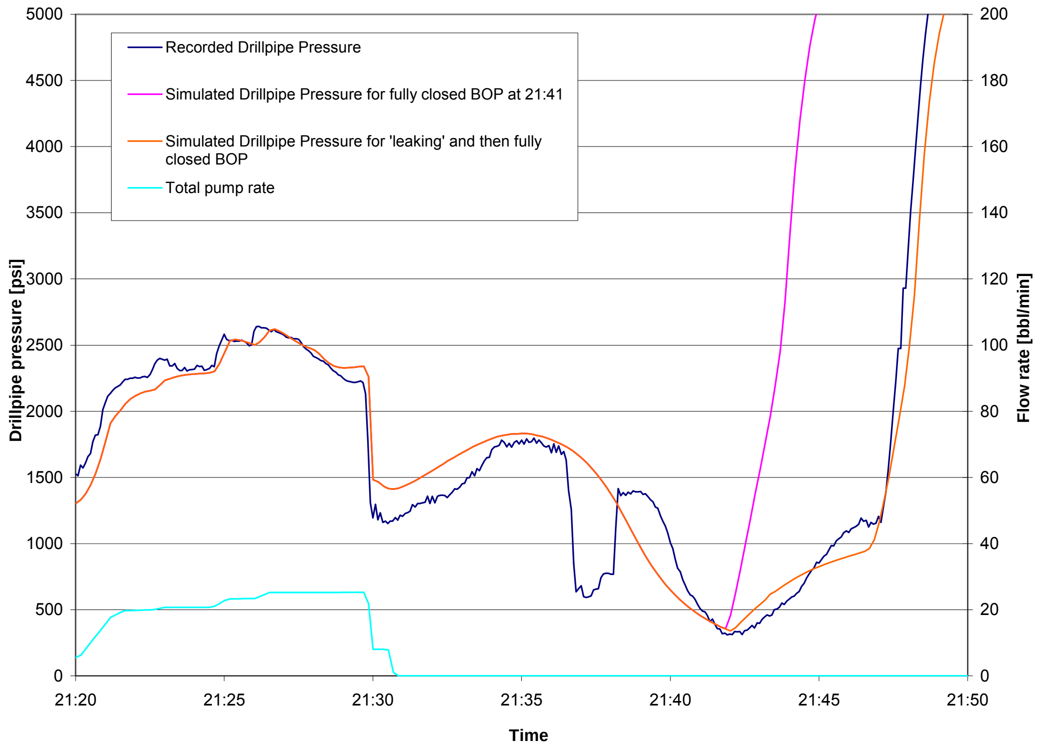


Figure 3.32:Case 7 - Pressure response for simulations with closing annular from 21:41 hrs (not accounting for the surface bleed).

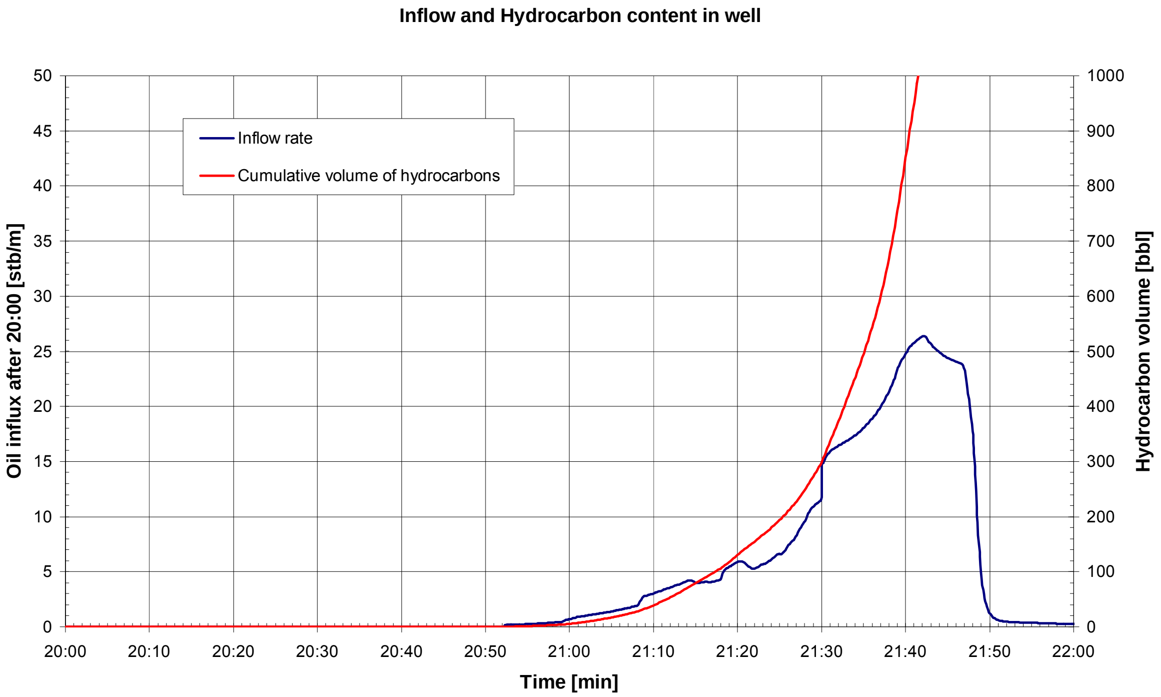


Figure 3.33:Case 7 - Inflow and hydrocarbon volume with closing annular from 21:41 hrs (not accounting for the surface bleed).

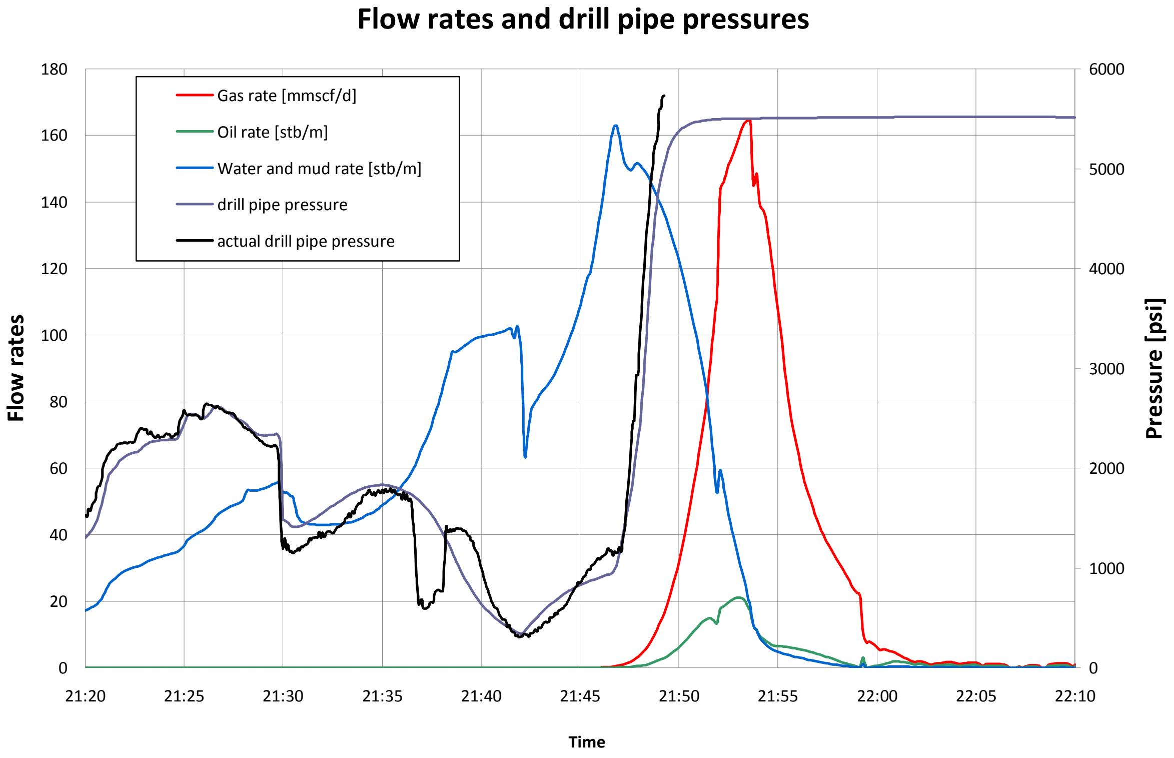


Figure 3.34: Case 7 - Flow and pressure at surface with closing annular from 21:41 hrs (not accounting for the surface bleed).

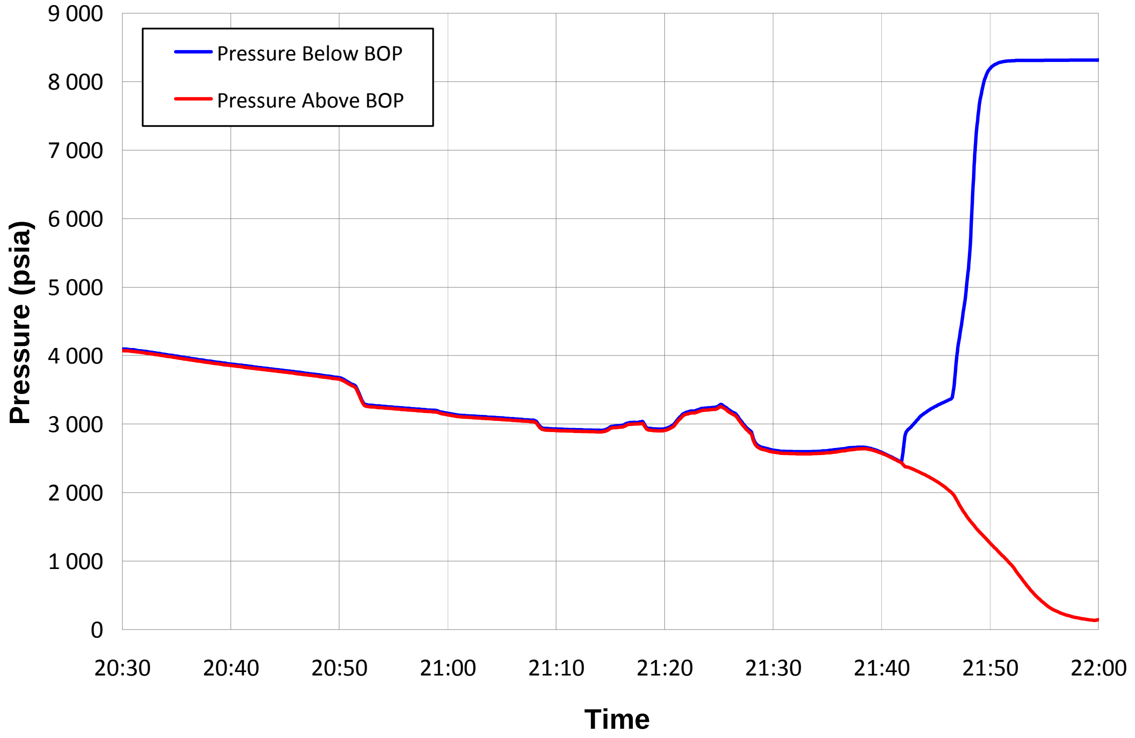


Figure 3.35: Case 7 - Pressure below and above the BOP when closing annular from 21:41 hrs (not accounting for the surface bleed).

3.8 Assumptions and Limitations

The main limitation of the OLGA modeling is the accuracy of the input assumptions. Every effort was made to align the model inputs to ensure a match with the available recorded data and actual events as witnessed. Actual recorded reservoir data for this well was used as an input, this significantly improves the degree of accuracy of the model. The model results should reasonably reflect what actually occurred.

There are other limitations and potential sources of error associated with the model results. One of these sources of error is the numerical diffusion caused by the gridding of the calculation cells, this tends to smear out the liquid fronts. This will have an influence on the transient calculation of the drill pipe pressure. OLGA Slug-tracking is a calculation module made to track these slugs, but the module has not been used as it is not compatible with the Drilling Option required for these calculations.

Further, the simulations include more than the three dedicated phases accepted by OLGA. Both the high viscosity spacer fluid, the 14 ppg mud and water were circulated though the well. All of these fluids are considered to be flowing in the "water phase" of OLGA meaning that they all travel with the same velocity and no swapping and migration is therefore possible.

The spacer is also challenging to model as this is a very viscous, non-Newtonian fluid. Additional pressure drop in the form of a restriction at the outlet was required in order to match the circulation pressures observed.

This report reflects the best judgment and analysis of add energy at the time of writing but with new evidence or assumptions other possible explanations to support the actual events may be plausible.

A. Appendix A

For the dynamic simulations, Olga-Well-Kill, (powered by OLGA version 5.3.2 from SPT Group) was applied. The simulator is tailor-made for well kill simulations and has been used in a number of on-site applications for blowout and well control. The development started in 1989 (during an underground blowout in the North Sea) based on the OLGA pipeline simulator. The model is a fully dynamic simulator that is capable of handling three different fluid phases simultaneously. The model is capable of handling non-Newtonian fluids; i.e. the viscosity is depending on the shear-rate. The OWK simulator handles a number of different flow configurations, e.g. annular flow, flow through bit nozzles, valves, pipe joints etc. See www.addenergy.no for more information.

The base core Olga code was presented in 1991 [ref. 14]. The original version of the Olga-Well-Kill model is described in a paper from 1996 [ref. 10]. Application of the model have been presented in a number of papers [ref. 1, 2, 4, 8, 11, 12 and 13].

Reservoir fluid characterization and property generation was performed by PVTsim version 19.1. This is the market leading fluid characterization and simulation software. See www.calsep.com for more info.

B. References

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